STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on August 13, 2026

COMMISSIONERS PRESENT:

Rory M. Christian, Chair
James S. Alesi
David J. Valesky
John B. Maggiore
Uchenna S. Bright
Denise M. Sheehan
Radina R. Valova

CASE 24-E-0621 - In the Matter of Modifications to the New York State Standardized Interconnection Requirements and Application Process for New Distributed Generators and/or Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems.

CASE 24-E-0415 – In the Matter of Timely Interconnection of Distributed Energy Resources.

ORDER ON INTERCONNECTION COSTS AND STUDY TIMELINES

(Issued and Effective August 17, 2026)

BY THE COMMISSION:

INTRODUCTION

In 2024, in different forums, developers of distributed energy resources (DERs) raised concerns about the costs and timeliness of interconnection under the State's Standardized Interconnection Requirements (SIRs).[1]

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[1] The current version of the SIRs is available on the Distributed Generation webpage of the Department of Public Service at https://dps.ny.gov/distributed-generation-information.

On April 20, 2024, the Renewable Action through Project Interconnection and Deployment Act (RAPID Act) was enacted, which directed the Public Service Commission (Commission) to consider establishing "metrics related to the timely interconnection of distributed generation resources into the distribution system owned by an electric corporation, as well as negative revenue adjustments related to such metrics."[2] The Commission initiated a proceeding in Case 24-E-0415 (i.e., the Metrics Proceeding) in response to that directive.

Also in 2024, DER developers raised objections in the Interconnection Policy and Interconnection Technical Working Groups (IPWG and ITWG, respectively, and collectively, the working groups) to increases in the Utilities'[3] interconnection cost estimates and in the actual costs of completed distribution system upgrades. Competing proposals were filed with the Commission during 2025 and early 2026 addressing these concerns about cost increases, as discussed below.

With this Order, we respond to the common issues raised in the various proceedings relating to cost estimating, increases in system upgrade costs, and the timeliness of interconnections. While we adopt several recommendations suggested by Department of Public Service (DPS) staff, the Utilities, and developers for improving the process, we decline to establish metrics or earnings adjustments related to the Utilities' performance of their interconnection obligations. We

[2] Chapter 58 of the Laws of 2024, Part O, §30.

[3] The Utilities include Central Hudson Gas & Electric Corporation; Consolidated Edison Company of New York, Inc.; New York State Electric & Gas Corporation; Niagara Mohawk Power Corporation d/b/a National Grid (National Grid), Orange and Rockland Utilities, Inc.; and Rochester Gas and Electric Corporation.

also decline to adopt a fixed cap on developers' responsibility for their interconnection costs.

BACKGROUND

The proceedings addressed in this Order and the overlapping claims and recommendations are summarized below.

The Metrics Proceeding

On April 20, 2024, Governor Hochul signed the RAPID Act into law, which, among other things, directed the Commission to "commence a proceeding within ninety days of the effective date of this act to review the cause and extent of any delays to interconnection of distributed energy resources" and "consider metrics related to the timely interconnection of distributed generation resources into the distribution system owned by an electric corporation, as well as revenue adjustments related to such metrics."[4]

The Commission established the Metrics Proceeding in response to that directive, and, on July 16, 2024, the Secretary issued a Notice Soliciting Comments on the Utilities' compliance with interconnection study timelines. On December 5, 2024, to address the ongoing discussions in the working groups concerning cost increases, the Secretary issued a Notice Soliciting Comments on the Utilities' interconnection cost estimating practices and procedures. A Notice Soliciting Further Comments on study timelines was issued by the Secretary on June 16, 2025.

DPS Staff Proposals

In 2024, the New York Solar Energy Industry Association (NYSEIA) and other participants in the interconnection working groups raised concerns about increases in the cost estimates DER developers were receiving with their

[4] RAPID Act, §30.

Coordinated Electric System Interconnection Review reports (CESIRs) as part of the SIRs. In response to these concerns, DPS staff filed two similar proposals for modifications to the SIRs.

On January 10, 2025, DPS staff filed its first recommendations to address these cost estimating issues in Case 24-E-0621 (hereafter, the "2025 Proposal"). DPS staff recommends several modifications to the SIRs, including (1) requiring the Utilities to publish and annually update a "cost matrix" covering typically necessary interconnection equipment; (2) removing a 15% contingency factor from the scope of utility cost estimates; (3) requiring Utilities to provide developers updated cost estimates for projects not in service within 12 months of their interconnection study; (4) removing language authorizing Utilities to change the cost estimates for a change in the scope of work; and (5) providing minor non-substantive clarifications. On January 31, 2025, the Secretary issued a Notice Soliciting Comments on the 2025 Proposal.

On January 16, 2026, DPS staff filed its second proposal relating to cost increase issues in the Metrics Proceeding, after reviewing the information on cost estimation filed by the Utilities (the 2026 Proposal). In its filing, DPS staff restates its earlier proposal to require the Utilities to publish annual updates to their cost matrix information and present those annual updates to stakeholders. DPS staff also proposes to incorporate the cost estimating matrix into the SIRs to ensure a standard level of transparency in cost estimating. Finally, DPS staff recommends requiring the Utilities to begin using the updated matrix information in their cost estimating work as of a fixed calendar date each year. Comments on the 2026 Proposal were solicited by the Secretary on March 13, 2026.

NYSEIA Cost Cap Petition

On February 14, 2025, NYSEIA filed a petition seeking modifications to the SIRs that would, among other things: (1) provide a greater level of detail in cost estimates; (2) establish a cap on a developer's obligation to pay for distribution upgrades; (3) require the Utilities to publish the actual costs of common upgrades annually; and (4) provide a "detailed, itemized, clear statement" of the final costs of the installed upgrades.[5]

The NYSEIA Cost Cap Petition notes that interconnection costs represent a significant percentage of a DER project's overall cost. NYSEIA states that the CESIR study cost estimates are therefore critical to a developer's decision-making, from undertaking permitting activities to raising capital for other development expenses. Pointing to cost estimate classifications produced by the Association for the Advancement of Cost Engineering (AACE), NYSEIA explains that an estimate at a screening level of confidence is not firm enough to support DER developers' financing needs.[6]

NYSEIA asserts that the cost estimates produced from 2022 to 2024 "have become increasingly unreliable."[7] NYSEIA indicates that National Grid adopted a new tool for estimating distribution upgrade costs in June 2024 that "produced significantly higher cost estimates than their recent prior estimation methods."[8] NYSEIA further contends that estimates

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[5] We refer to this filing as the "Cost Cap Petition," although it also raises issues in common with the Metrics Proceeding (Case 24-E-0415) and the 2025 Proposal in the SIRs Modifications proceeding (Case 24-E-0621). See Cost Cap Petition, pp. 2-3.

[6] Id., p. 4.

[7] Id., p. 5.

[8] Id., p. 6.

based on the new tool in 2024 were approximately 71% higher than estimates produced a few months earlier.[9] NYSEIA complains that the new approach was introduced without any regulatory oversight or any substantiating data. NYSEIA states that other Utilities have also been delivering increased cost estimates.[10] Further, NYSEIA claims that minor revisions to projects studied in 2023 resulted in cost estimate increases above 200%.[11] NYSEIA argues that such variability indicates that either the original or the revised estimate was "erroneous."[12]

In addition, NYSEIA asserts that, separate from the issue of changing cost estimates, the actual costs of completed projects increased beyond the original estimates provided for those projects. NYSEIA states that developers have incurred unacceptably high "retroactive" cost increases, noting that Altamont Solar LLC incurred a cost overrun in excess of $1 million in one case, and that many other developers have also been impacted by utility cost overruns but have not shared their cost data publicly.

NYSEIA argues that the SIRs do not properly allocate the risk of utility cost overruns. NYSEIA notes that the SIRs require developers to pay the final costs of distribution upgrades without giving developers any control over the work or the costs. NYSEIA suggests that a strong regulatory framework is needed to ensure that Utilities are responsible for their costs and performance.

NYSEIA claims that rising distribution upgrade costs reduce the economic viability of DER projects and slow their

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[9] Ibid.

[10] Id., p. 2.

[11] NYSEIA provides no evidence for this claim.

[12] Id., p. 7.

deployment.[13] NYSEIA posits that rising costs also impact the cost of ratepayer-funded incentives that are necessary to meet the State's renewable energy targets and that the "growing uncertainty" erodes investor confidence in New York projects.[14]

NYSEIA indicates that developers dependent on significant upgrades that are subject to cost-sharing, such as substations, need greater cost certainty. NYSEIA attributes this to the length of time required to develop and construct these upgrades, which increases the risk that actual costs will exceed the estimates provided to developers earlier in the process.

NYSEIA suggests that the uncertainty created by cost increases can be resolved by establishing the 15% contingency recognized in the SIRs cost estimating rules as a hard cap on developers' payment obligations.[15] NYSEIA proposes implementing this approach through a modified interconnection agreement, which would be structured as a "Guaranteed Maximum Price" contract, under which any overrun risk would be borne by the utility. NYSEIA points to tariff provisions in Massachusetts, Rhode Island, and California that NYSEIA claims establish a hard cap on distribution costs in those states.

NYSEIA also argues that, because developers have no option but to sign the interconnection contract with the utility, strong disincentives are necessary to deter Utilities from inflating their cost estimates, even with a cost cap. The solution to this problem, according to NYSEIA, is greater transparency into the Utilities' actual costs and a mechanism to validate cost estimates. NYSEIA recommends that the Commission

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[13] Ibid.

[14] Id., p. 8.

[15] Id., p. 9.

establish a formal audit process to "verify utility compliance with cost estimation standards, assess the alignment of estimates with actual costs, and ensure accountability."[16]

NYSEIA's petition concludes with the request that the Commission implement six measures to address the problem of rising costs and increased cost estimates. First, NYSEIA asks the Commission to require greater detail in cost estimates, including "equipment type, quantity ... technical specifications, and estimated internal and subcontract labor costs."[17] NYSEIA recommends that the Commission require labor rates and hours to be included, with assumptions about escalations, and disallow any indirect costs or overheads that the utility cannot itemize.

Second, NYSEIA repeats its request for the Commission to impose a hard cap on the amount a utility can charge a DER developer for the final costs of distribution upgrades. NYSEIA proposes to cap a developer's responsibility at 115% of the CESIR cost estimate. The cap would be binding for 36 months following issuance of the CESIR; NYSEIA states that this time period reflects "typical development and construction timelines."[18] NYSEIA suggests that requiring the Utilities to document key milestones, such as procurement dates, construction start dates, and completion dates, would "ensure the validity of cost estimates."[19]

Third, NYSEIA advocates for an annual process in which the Utilities would file their actual costs of common upgrades for public review. NYSEIA asks the Commission to incorporate

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[16] Id., p. 10.

[17] Id., p. 12.

[18] Id., p. 13.

[19] Ibid.

the ITWG cost matrix into the SIRs and to direct the Utilities to provide their costs by equipment, labor, and other major cost categories. Each annual matrix would undergo public review and comment prior to being adopted by the Commission. The Utilities would thereafter be required to use their matrices in developing CESIR cost estimates.

Fourth, NYSEIA asks the Commission to require the Utilities to provide a detailed accounting of how upgrade funds were spent. Under the NYSEIA request, a utility would be required to provide an itemized statement showing the utility's actual costs within 60 business days after allowing a project to operate. Where the actual costs exceed the estimate by more than 15%, the utility would provide an explanation for the deviation.

Fifth, NYSEIA states that the Utilities should be allowed to seek recovery of "prudently incurred" costs that exceed 115% of a CESIR cost estimate in rate cases. NYSEIA explains that this would protect both interconnection customers and ratepayers from unreasonable cost overruns. Sixth, NYSEIA reiterates its request that the Commission establish an annual auditing process to "verify utility practices and promote accountability."[20]

The ASAP Act

As part of the State budget legislation, on May 26, 2026, the Accelerate Solar for Affordable Power (ASAP) Act was enacted, which contains several directives related to interconnection processes.[21] Among other things, the ASAP Act requires the Commission to undertake a proceeding to require

[20] Id., p. 15.

[21] Chapter 58 of the Laws of 2026, Part SS, Accelerate Solar for Affordable Power Act (ASAP Act), codified in part, in Public Service Law (PSL) §66-aa.

electric utilities to file annual reports delineating the "costs of completed upgrades to the electric distribution system required in order to interconnect new distributed energy resources ... categorized by upgrade type and equipment type."[22] The ASAP Act also directs the Commission to commence a proceeding "to consider proposals to create greater cost-certainty for distribution upgrades in order to limit the risk of cost overruns."[23] We note that this Order only addresses the sections of the ASAP Act that are codified in PSL §66-aa, which are focused upon interconnection cost transparency and cost certainty.

NOTICE OF PROPOSED RULE MAKING

Pursuant to the State Administrative Procedure Act (SAPA) §202(1), a Notice of Proposed Rule Making (Notice) was published in the State Register on January 29, 2025 [SAPA No. 24-E-0621SP2] related to DPS staff's January 2025 proposal. The Secretary issued a Notice Soliciting Comments on the proposal on January 31, 2025. On February 26, 2025, the Secretary issued a Notice Soliciting Comments on NYSEIA's Cost Cap Petition and a Notice of Proposed Rulemaking regarding NYSEIA's proposal was published in the State Register on March 12, 2025 [SAPA No. 24-E-0621SP3]. A Notice of Proposed Rulemaking regarding DPS staff's second proposal was published in the State Register on February 4, 2026 [SAPA No. 24-E-0415SP1]. In addition, the Secretary issued a Notice Soliciting Comments on DPS staff's second proposal on March 31, 2026.

[22] PSL §66-aa(1)(a).

[23] PSL §66-aa(2).

SUMMARY OF COMMENTS

A full summary of the comments is included in Appendix A. In general, comments were received on each proposal, including from the City of New York (the City), the Utilities, industry groups, DER developers, and other stakeholders. Each commenter expressed support for one or more of the proposals. Some commenters suggested modifications or offered alternative proposals relating to the interconnection process. The comments are summarized in Appendix A and addressed in the body of this Order.

LEGAL AUTHORITY

The Commission has broad authority over the manufacture, conveyance, sale, or distribution of electricity, supervision of electric corporations, and the responsibility to ensure that all service, instrumentalities, and facilities furnished shall be safe and adequate and all charges made by such corporation for any service rendered shall be just and reasonable.[24] The Commission also has the authority to direct the treatment of DERs by electric corporations.[25] In addition, the RAPID Act and ASAP Act direct the Commission to commence proceedings and take certain actions related to interconnection processes, as described above.

DISCUSSION

In this Order, we discuss the results of our review of the NYSEIA Cost Cap Petition, the record of the Metrics Proceeding, the DPS staff proposals, and the comments. We focus on the common issues that have been raised in these proceedings:

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[24] PSL §§5, 65, and 66.

[25] PSL §§5(2), 66(1), 66(2), 66(3), 66-c, 66-j, and 74.

interconnection delays, increases in interconnection cost estimates, and increases in the actual cost of utility interconnection work.

As discussed below, we find that the Utilities' cost estimating methods are reasonable but agree with the commenters that increased transparency would be helpful to developers planning projects. We agree that cost certainty is important for the market but decline to adopt a cap on a developer's obligation for the actual costs of the system modifications needed to interconnect its project. Similarly, we determine that the Utilities have generally performed CESIRs within the timeframes authorized by the SIRs but also adopt recommendations to clarify the circumstances in which the Utilities may exceed the standard 60-business day period. We decline to impose, at this time, performance metrics on the Utilities relating to interconnection.

CESIR Study Timelines

The RAPID Act requires us to consider "metrics related to the timely interconnection of distributed generation resources into the distribution system owned by an electric corporation, as well as revenue adjustments related to such metrics."[26] As explained above, the CESIR is the key step in the interconnection process. It provides the utility and the interconnecting customer with the information they need to proceed to construct the proposed project and to complete the interconnection in a safe and reliable manner. The SIRs impose limits on the time a utility has to perform a CESIR once complete information is received from the interconnection applicant. In the ordinary course, that timeframe is 60

[26] RAPID Act, §30

business days.[27] However, the applicant and the utility may agree to allow an additional period of up to 40 business days.[28]

In response to DPS staff's requests, the Utilities filed information in the Metrics Proceeding concerning their compliance with the SIRs deadlines. These data cover the period of September 1, 2019, to August 31, 2024. We have reviewed that information, as well as the analysis submitted by the New York State Energy Research and Development Authority (NYSERDA), which reports that the Utilities completed 78% of all CESIR studies within 60 business days and 95% of all CESIR studies within the extended SIRs limit of 100 business days.[29] Pursuant to the SIRs, the applicant and the utility may agree to allow up to 40 additional business days to complete the CESIR. Typically, projects with agreed-upon CESIR timeline extensions involve more complex review and analysis by the utility, such as hybrid projects and projects with unique complexities.

These data do not conclusively demonstrate that performance metrics are necessary to ensure "the timely interconnection of distributed generation resources." Rather, NYSERDA's analysis, summarized in the table below, shows that the Utilities deliver over three quarters of all CESIRs within the 60-business day deadline, and that almost all studies are completed within the additional 40 business days allowed by the SIRs.[30]

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[27] SIRs, Section I, Step 6.

[28] Ibid.

[29] Case 24-E-0415, NYSERDA Analysis of CESIR Study Timelines (filed April 3, 2026).

[30] The number of CESIRs that go beyond the authorized period is 241 of the 4,535 CESIRs completed over the study period, or 5.3%.

Duration of CESIR Review	Central Hudson	Con Edison	National Grid	NYSEG	RG&E	Orange & Rockland	Total
10 Days or Less	-	6	51	4	-	-	61
11-20	1	19	28	20	3	-	71
21-30	-	26	45	10	2	-	83
31-40	-	73	37	5	4	1	120
41-50	-	627	55	128	32	8	850
51-60	121	683	682	658	111	58	2313
61-70	12	2	142	41	5	4	206
71-80	-	3	168	10	2	-	183
81-90	1	-	159	9	-	-	169
91-100	5	8	138	8	2	-	161
Over 100	3	1	219	15	1	2	241
Total	143	1448	1724	908	162	73	4458
Percent of Completed CESIRS 60 Days or Less	85%	99%	52%	91%	94%	92%	78%
Percent of Completed CESIRS 100 Days or Less	98%	100%	87%	98%	99%	97%	95%

Thus, we cannot conclude that the Utilities have delayed the interconnection process. Rather, it appears from the data that the Utilities’ performance of this key part of the interconnection process meets the timing requirements of the SIRs. The record of these proceedings does not indicate a need for the Commission to impose additional discipline on the process.

However, to facilitate effective oversight of the utilities’ compliance with the timelines established in the SIRs and to increase transparency, we direct the Utilities to annually file data indicating the number of business days taken to complete a CESIR and identifying the duration of any extension agreed upon pursuant to the SIRs, for each CESIR completed in the prior calendar year, beginning March 31, 2027, in Case 24-E-0621.

In addition, we note that other information provided by the Utilities strongly suggests that factors outside the interconnection process play a major role in how long it takes for a project to enter service. The Utilities' data, as noted above, indicates that DER projects take between 2.75 and 4.5 years to interconnect, after receiving their the CESIRs. Thus, we conclude that it is not the interconnection study process that is driving these extended timeframes but some other factor. We note that the steps in the SIRs, after the CESIR, include the developer's payment of the utility cost estimate, which is a fixed milestone, followed by construction. It appears that developers largely make their payments on time because they risk being removed from the interconnection queue if they are late. Thus, it is likely that the extended times to completion are due to factors such as local permitting, financing delays, and equipment procurement, all of which occur outside the interconnection process established by the SIRs. In any event, we reject NYSEIA's assertion that failures in the interconnection process are the cause of excessive delays in project completion. However, developers concerned about delays with their CESIRs should reach out to the relevant utility ombudsman and the DPS staff ombudsman for assistance. Contact information is available at https://dps.ny.gov/interconnection-ombudsman-effort.

The initial results of a CESIR may give either or both parties an indication that additional work is needed. For the developer, the CESIR may show that the proposed project is uneconomic as designed. In this situation, the applicant may be interested in modifying or downsizing the project. So long as the proposed change does not amount to a Material Modification, as defined in the SIRs, the developer and the utility should use the additional 40-business day period to address this situation.[31] On the other hand, the CESIR may indicate to the

[31] Material Modifications are addressed in Section I of the SIRs.

utility that additional study is necessary, as when a particular project may have impacts upstream of the distribution system. In that case, taking the additional study time is warranted to make sure the project can be safely and reliably interconnected.

For these reasons, we will maintain the existing SIRs study timeframes, with the adoption of the clarifying text indicated in Appendix C to this Order and the directive for the Utilities to annually file their CESIR study timeline compliance data. We also decline to establish performance metrics or revenue adjustments related to the timeliness of the interconnection process.

Interconnection Cost Estimates

In the Cost Cap Petition, NYSEIA asserts that the Utilities' cost estimating procedures are "increasingly unreliable."[32] However, the information before us does not support this claim.

Upon review of the Utilities' submissions in the Metrics Proceeding concerning their cost estimating methods, we find that, while there are variations from utility to utility, the Utilities utilize relevant data, make annual updates, and have procedures in place to guide their estimating teams. We note that the estimating processes consider material costs, labor rates, overhead, and factors allowing adjustments for field conditions. We also note that several utilities indicated in their responses to the December 5, 2024 Notice Soliciting Comments in Case 24-E-0415, that they had not changed their interconnection cost estimation processes during the period in which NYSEIA asserts that the cost increases took place. National Grid, NYSEG, and RG&E explained their modifications of cost estimating procedures during that period. National Grid

[32] Cost Cap Petition, p. 5.

indicated that it began using a new estimating tool in 2024, for DER interconnection costs and across all engineering groups, which uses annually updated costs for common work scopes. NYSEG and RG&E explained that a "Customer Funded Development group" was established to provide consistency in cost estimates and engage internal experts on a project-to-project basis. Additionally, the Utilities explained these changes to participants in the ITWG and stakeholders did not raise concerns with the changes in the working groups or in their filings in these proceedings. We have reviewed the record of these proceedings and conclude that the Utilities' methods do not appear to be flawed in a way that would make the results inherently unreliable. As we discuss below, a DPS staff report developed in the ITWG in 2025 shows that, on average, final project costs over the 2020 through 2024 period were either similar to, or often lower than original estimates.[33]

Furthermore, NYSEIA's assertion that the estimates are unreliable is not well-founded. NYSEIA acknowledges that the ITWG initially developed a cost estimating matrix in 2019 and does not dispute the fact that National Grid's July 2024 update showed significantly higher costs than were reported in 2019. NYSEIA argues that, because the estimates increased over that time, either the estimates based on 2019 information or the new estimates based on 2024 information must be erroneous. This has not been demonstrated in the record of these proceedings.

We find that there is a straightforward explanation for the increases in estimates prepared based on 2019 data and 2024 data. We know that costs throughout the energy sector

[33] See Appendix B and materials from the February 26, 2025 ITWG Meeting available at https://dps.ny.gov/system/files/documents/2025/02/dps-sir-cesir-cost-analysis-2020-2024.pdf.

increased significantly between 2019 and 2024. The Commission acknowledged the national and global circumstances that resulted in these increases in its 2023 decision rejecting petitions by large scale renewable developers for an adjustment in their NYSERDA contracts.[34] The resulting cost increases, as they extended to the DER sector, are illustrated in the table National Grid provided to the IPWG at the July 2024 meeting, which is reproduced below. According to National Grid, cost increases during that period ranged from 25 to 138 percent for various types of equipment.

Historical Material Pricing 2019 vs 2024 – Common DG Materials

Note: this is an illustrative snapshot – this is not a comprehensive list

Item	Unit of measure	2019 Price	2024 Price	19 vs 24 Change	Peak Price
600A, D5D Switches	EA	$ 192.78	$ 286.00	48%	$ 315.32
Wood Pole 45 class 3	EA	$ 401.29	$ 530.00	32%	$ 1,850.00
167KVA Regulator	EA	$ 15,066.00	$ 20,184.00	34%	$21,793.00
333KVA Regulator	EA	$ 18,712.00	$ 23,328.00	25%	$24,598.00
Recloser, G&W Loop	EA	$ 15,995.00	$ 20,371.00	27%	$22,408.00
336AAAC OH Cond	LF	$ 0.59	$ 1.23	109%	$ 1.23
1/0AAAC OH Cond	LF	$ 0.23	$ 0.54	138%	$ 0.59
1000 KCMIL Copper	LF	$ 45.92	$ 89.78	96%	$ 273.50
2500KVA Pad Transf 13.2-480v	EA	$ 17,199.00	$ 40,897.00	138%	$92,688.00
500Cu UG Cable, 15kV	LF	$ 30.44	$ 43.23	42%	$ 138.00
1000Al UG Cable, 15kV	LF	$ 15.89	$ 30.40	91%	$ 30.40
500Cu Straight Splice	EA	$ 288.83	$ 491.10	70%	$ 491.10

Though the table above is specific to National Grid, we note that all Utilities state in their response to the December 5, 2024 Notice that they have experienced both equipment and labor cost increases, due to a combination of supply chain constraints, commodity price increases, and updated labor agreements.

[34] Case 15-E-0302, Large-Scale Renewable Proceeding, Order Denying Petitions Seeking to Amend Contracts with Renewable Energy Projects (issued October 12, 2023).

However, even without the disruptive events during 2019-2024 of the national and global COVID pandemic, the Russian invasion and war in Ukraine, supply chain impacts, and inflation, and subsequent circumstances of high federal tariffs and the war in Iran and disruption of maritime commerce, we would normally expect costs to rise over such an extended period of time.[35] We would also expect, and any market participant should expect, that utility cost estimates would reflect the same economic trends. Though some utilities updated their cost estimation methodology during this period, we find that if these changes increased the estimated costs relative to what the estimated costs would have been under the utilities' previous methodology, the cost increases would likely represent a more accurate prediction of an interconnecting project's costs, as previously discussed. For these reasons, the fact that estimates delivered with CESIRs developed in 2023 or 2024 were higher than estimates calculated in 2019 or 2020 does not suggest there is any fundamental defect in the Utilities' approach to cost estimating. Rather, we view the upward slope in cost estimates as the predictable result of national and global economic trends. Had utility cost estimates remained unchanged during the intervening period, it would run contrary to evidence received through multiple rate cases and suggest a significant subsidization of costs in favor of developers at the expense of other ratepayers.

A review of cost estimates compared to actual costs also persuades us that the Utilities' estimating practices are

[35] NYSEIA agrees with this observation, conceding that the long lead times to constructing shared upgrades increase the risk of actual costs exceeding estimates delivered years earlier. Cost Cap Petition, p. 8.

reasonably reliable.[36] A DPS staff report developed in the ITWG in 2025 shows that, on average, final project costs over the 2020 through 2024 period were either similar to, or often lower than original estimates, as shown in Appendix B.[37] The analysis performed by DPS staff and presented in the ITWG included reviewing the actual costs of upgrades for projects completed in 2020-2024, compared to the CESIR cost estimates provided by the Utilities. This data was also examined for projects completed during a two-year timeframe (2023-2024) and during the single year of 2024 to determine whether the results changed during specific periods and to develop a fuller view. During this ITWG meeting, participants did not dispute or otherwise express concerns about the accuracy of this analysis or the data with which the analysis was done, nor did parties dispute the analysis or underlying data in their filings. This information suggests to us that the Utilities' estimates have been reasonably reliable indicators of a project's likely interconnection costs. While there may have been individual projects that experienced exceedances during the time period the ITWG reviewed, the data strongly suggest that, on average, the Utilities' cost estimating methods produce reasonably reliable results. Also, we note that Step 11 of the SIRs requires utilities to reimburse interconnection applicants for overpayments identified in the utilities' final reconciliation statements.

[36] NYSEIA states that "the cost must be certain enough for budget authorization" and argues that a lack of cost certainty discourages the industry from investing in New York. Cost Cap Petition, p. 4.

[37] See materials from the February 26, 2025 ITWG Meeting available at https://dps.ny.gov/system/files/documents/2025/02/dps-sir-cesir-cost-analysis-2020-2024.pdf.

However, as discussed above, our determination that the Utilities' practices produce reasonable results does not overlook opportunities for improvement or for offering developers greater cost certainty, which we agree is necessary to sustain the market. First, we acknowledge that the level of certainty in cost estimates is at least partly a function of the amount of time the Utilities have to prepare them under the existing SIRs deadlines.[38] We find that the Utilities could deliver more granular cost estimates if given sufficient time to develop them. As NYSEIA notes, engineering standards are available to determine project cost estimates at increasing levels of certainty.[39] NYSEIA's submissions suggest that some developers might benefit from an opportunity to request an estimate designed to a higher confidence level than the Utilities are currently targeting, if needed for their individual project financing purposes. At the same time, we agree with the Utilities that they will likely need additional time under the SIRs to generate such estimates.

We therefore direct the Utilities to file a proposal in Case 24-E-0621 with the Commission identifying (1) the methods they will use to provide a cost estimate at an increased level of confidence, if requested by a developer, and (2) the amount of additional time they need to produce such cost estimates. As the Utilities' comments indicate, increased cost certainty can be achieved through additional studies, detailed designs, and additional time.[40] We do not adopt a specific cost

[38] The Utilities explain that preparing more detailed estimates would require completing more detailed designs and conducting site visits, which would necessitate a longer timeframe. Utilities' Comments, pp. 11-12.

[39] NYSEIA Cost Cap Petition, pp. 4-5.

[40] Utilities' Comments on NYSEIA Cost Cap Petition, pp. 11-12.

estimating standard at this time, which the companies say would require several additional months of engineering work to meet in each case, but we expect the Utilities to propose a workable approach that provides additional confidence. We will require the Utilities to engage with participants in the ITWG to determine what standard is most appropriate for the interconnection process; that standard may be the AACE Class 3 standard or some other standard that the parties determine is supportive of investment decision-making. We require the Utilities to consider when a site visit is a necessary element of such a higher-level estimate, and to identify in the filing the types of applications that they believe should require a site visit before the higher-confidence estimate is finalized. We also require the Utilities to identify what level of detail will be included in such cost estimates and explain the rationale for that level of detail, after considering input from stakeholders in the ITWG. The Utilities shall make this filing no later than January 15, 2027.

We further agree with DPS staff and commenters that more transparency in the cost estimating process would provide additional certainty to developers. Indeed, there is near-unanimity on the need to formalize the ITWG process for updating the utility cost matrix. Therefore, we adopt the proposal made by DPS staff to require each utility to publish its cost matrix on its DER interconnection portal by March 31 of each year, to file the matrix in Case 24-E-0621, and to present proposed updates to stakeholders at the ITWG prior to that filing. This information should cover the equipment and tasks that are common to most interconnections. The matrix filing must also be accompanied by supporting documentation that identifies the actual costs of upgrades completed for projects that were interconnected in the prior calendar year, broken down by upgrade and equipment type, as required by the ASAP Act.[41] We will also require the Utilities to base the CESIR cost estimate on the cost information used to develop the current cost matrix, in accordance with the ASAP Act, with adjustments or additions required for the specific DER project.[42] SIRs amendments implementing these requirements are included in Appendix C and will be incorporated into utility tariffs.

We decline to establish the extensive regulatory process requested by NYSEIA, which would include Commission review of, and action on, the cost matrices. NYSEIA's proposed process would add several months to the process of updating the information used for cost estimates, as well as burdens on DPS staff and the Utilities, with no clear gain in the reliability of the cost estimates.[43] Under such a process, the cost matrices could not be finalized until the third quarter of each calendar year, to allow for additional process and public comments, which would occur shortly before the updated matrices for the next year would be developed and filed. Our intent in requiring the filing of the cost matrices is to ensure transparency into typical interconnection costs for all interested stakeholders, and to preserve a public record of the data as it evolves over time. Because the parties with the greatest interest in the cost estimating process – DER developers -- will continue to have an opportunity at the ITWG to review the information and raise questions directly with the Utilities, we find that there

[41] PSL §66-aa(1)(a).

[42] Ibid.

[43] We note above that the Utilities' cost estimating has produced reasonably reliable results in that the estimates align well with the reported actual costs. Thus, we see little to gain by adding Commission-level scrutiny to the data used in the matrices.

is no need for us to intervene and regulate the development of cost estimates.

Actual Costs and Cost Cap

NYSEIA bases its request for a cost cap on claims of excessive cost overruns. We reject this request because the information in the record does not support NYSEIA's premise. If the information developed in these proceedings suggested a significant problem with utility costs consistently exceeding estimates, we would agree with NYSEIA that some kind of control was necessary to improve market confidence. However, as noted above, the record in these various proceedings does not support NYSEIA's complaint that Utilities are incurring costs in an irresponsible manner. Costs have risen over the last seven years but the record shows that the Utilities are, for the most part, completing projects within the range of the estimates provided to developers. These facts do not justify establishing a cap on developers' payment obligations and potentially exposing ratepayers to the risk of rising costs. We note that NYSEIA's proposal for a 36-month cost cap would directly shift the risk of inflation to ratepayers, even before questions of utility prudence could arise. Furthermore, we agree with the Utilities that establishing a cap on upgrade costs would inappropriately shift the risk of cost increases from interconnection applicants to utility customers, contrary to cost causation principles. In addition, we are persuaded by the Utilities' assertion that some of the cost increases experienced by developers may be the result of the years many projects remain in development after receiving the CESIR.[44]

For these reasons, we will not convert the 15% contingency into a cap on developers' SIRs obligation to pay the actual costs of system modifications. We also reject DPS staff's suggestion to remove the contingency from utility cost estimates. Utilities shall continue to incorporate the contingency in the CESIR estimates they deliver to interconnection applicants, and we clarify that it does not function as a cap on the actual costs for which developers are responsible. We will, however, require DPS staff and the Utilities to conduct periodic assessments of the consistency of cost estimates and actual project costs. Each assessment will review cost data on a rolling basis for a five-year period. We direct the Utilities to file cost estimate and actual cost data for completed projects every year, in Case 24-E-0621, beginning March 31, 2027, and initially encompassing projects completed from 2022-2026. DPS staff will include discussion of the data at an ITWG meeting following the Utilities' filings.

<u>ASAP Act</u>

We recognize that the recently enacted ASAP Act directs the Commission to commence a proceeding to require the Utilities to file annual reports of distribution upgrade costs (by upgrade and equipment type) for interconnecting DERs.[45] Our directive in this Order for the Utilities to annually file cost

[44] The record here shows that cost increases result from many factors, some of which the Utilities can control while others – such as global supply chain disruption and the pace of the developer's work – are outside their control. The allegation that costs increased from the start to the finish of a project is insufficient to suggest any improper allocation by the utility.

[45] PSL §66-aa(1)(a).

matrices, appending the actual costs of completed upgrades, and to base cost estimates on the same information, fulfills that requirement of the ASAP Act.

The ASAP Act also requires the Commission to undertake a proceeding to consider proposals to create greater cost certainty for distribution system upgrades and "to determine whether any such proposal would increase cost certainty for distribution upgrades, would not negatively impact the operation of the distribution system, and would not increase costs to ratepayers."[46] We note that the Commission has been inviting and considering various proposals related to cost transparency and cost certainty in these proceedings and through the interconnection working groups over the past 18 months. For instance, we explicitly requested stakeholder input regarding "[w]hat measures, tools, or steps are available to increase the accuracy of the cost estimates provided to DER developers" in the December 5, 2024 Notice Soliciting Comments in Case 24-E-0415. In addition, both the Interconnection Technical Working Group and the Interconnection Policy Working Group have been discussing cost certainty and cost transparency over the past several years.

The actions we are taking to increase cost transparency and cost certainty through this Order are the result of extensive analyses by DPS staff, stakeholder engagement in the working groups and formal comments, and our balancing of the interests to provide greater cost certainty to interconnection applicants without negatively impacting the operation of the distribution system or increasing costs to ratepayers. Accordingly, we find that our consideration of the proposals and robust record in these proceedings, culminating in

[46] PSL §66-aa(2).

the directives we are adopting in this Order, fulfills this statutory obligation. By requiring detailed annual filings of upgrade costs and regularly conducting comparisons of estimated versus actual costs, we are providing DPS staff and stakeholders with information and analyses that can be used to develop proposals for additional modifications to the SIRs, when warranted. To that end, we encourage stakeholders to propose potential process improvements in discussions with the interconnection working groups and to file such proposals in Case 24-E-0621 for consideration by the Commission.

We also note that the ASAP Act directs the electric utilities to track and disclose to DPS and the DER interconnection applicants the actual costs of completed upgrades.[47] No further action appears necessary with respect to this provision, as the Utilities already provide the actual upgrade costs as part of Step 11 of the existing SIRs. Finally, as we indicated above, this Order only addresses the sections of the ASAP Act that are codified in PSL §66-aa, which are focused upon interconnection cost transparency and cost certainty. Other provisions of the ASAP Act, which are not directly related to the transparency and certainty of interconnection costs, will be addressed by the Commission separately.

Other Related Issues

We reject NYSEIA's request that we establish a formal annual audit process involving Commission review and "verification" of the data used by the Utilities to prepare cost estimates. The steps we take with this Order address stakeholder concerns about greater transparency in cost estimating and the need to monitor the alignment of estimates with actual costs; we do not believe further Commission

[47] PSL §66-aa(1)(b).

intervention is necessary. The availability of more cost information at the ITWG and in the filings we have directed in this Order will improve stakeholders' ability to make informed planning decisions. However, we also note that the Commission has authority under the Public Service Law to conduct a review or formal audit whenever it determines that such a process is warranted.[48]

We reject the request to disallow "indirect costs and overheads." These are specifically recognized as a component of the cost estimate under the SIRs. As the Utilities demonstrate, the companies account for overhead costs for construction projects pursuant to the applicable accounting rules, and NYSEIA has stated no reason why DER developers should not be responsible for their shares of a utility's overhead allocated to building their projects. We will not require the Utilities to itemize the costs they include in their overhead calculations; this information is identified in the Uniform System of Accounts.[49]

We decline to require more detail in cost estimates at this time. The SIRs currently provide that: "Utility cost estimates provided in the CESIR shall be detailed and broken down by specific equipment requirements, material needs, labor, overhead, and any other categories." The Utilities indicate that their contracts with suppliers include non-disclosure and confidentiality provisions that limit their ability to publicly reveal the rates and commercial terms contained in those contracts. The record in these proceedings does not establish what level of detail would be useful to project developers and for what purpose and benefit. Accordingly, we require DPS staff

[48] PSL §§5, 65, 66, and 66-j.

[49] 18 CFR §367.52.

to explore this issue in the ITWG, within 90 days of the effective date of this Order. Any proposal to modify the level of detail required in cost estimates should be filed in Case 24-E-0621 and, at a minimum, explain how the proposed level of detail will be useful and address the confidentiality issues raised by the Utilities.

NYSEIA asks us to require "detailed accounting" from the Utilities for the funds spent on interconnecting DER projects. The SIRs provide a 60-business day deadline for delivery of the reconciliation statement following completion of a project. NYSEIA does not claim that the Utilities have not been meeting this requirement, while the Utilities state that the current period is more difficult to manage as projects get more complex. We agree with the Utilities, who recommended taking up this issue in the stakeholder process. Accordingly, we direct the Utilities to present a proposal in the IPWG on the minimum amount of time that is necessary to ensure complete and accurate reconciliations. The proposal, along with any proposed modifications to the SIRs to effectuate the proposed process, shall be filed in Case 24-E-0621 within 90 days of the effective date of this Order.

In addition, in response to commenters' concerns about transparency in reconciliation statements, we amend the SIRs as provided in the attached Appendix C to require Utilities to meet with developers after delivery of the reconciliation statement and to explain any cost increases that exceed the 15% contingency included in the CESIR estimate.

Finally, we acknowledge that commenters sought to raise additional issues and made proposals ancillary to the central issues of cost and interconnection timeliness that are the subject of this Order. We do not address those suggestions here today.

Where potential changes to the SIRs are implicated, we rely on the working groups to prioritize stakeholder and utility concerns, review the merits and feasibility of solutions, and develop specific recommendations. Stakeholders seeking changes to the interconnection process should, therefore, bring such proposals to the ITWG and IPWG, as appropriate, for prioritization, exploration, and analysis. We emphasize that the Commission established these two groups to serve as the primary forums for raising, and discussing, vetting, and analyzing potential modifications of the SIRs. We reiterate that objective in this Order and underscore our expectation that stakeholders and utilities will abide by these parameters and address such issues in the working groups. If NYSEIA or any other stakeholder believes further modifications to the SIRs are necessary, they are to bring them forward at the IPWG and ITWG in a prioritized, methodical, and stepped manner.

Changes are best addressed through the working groups because this approach ensures that any changes adopted receive statewide effect, creating a uniform set of rules and requirements. The benefit of such approach is consistency. Regardless of where a solar facility is installed, the industry will operate under the same statewide standards. This eliminates fragmentation across utility service territories, reduces compliance complexity, and provides installers with regulatory certainty while ensuring utilities, DPS staff, and other stakeholders can rely on uniform statewide practices.

Environmental Compliance

Pursuant to the Climate Leadership and Community Protection Act (CLPCA) §7(2), the Commission finds that the actions taken herein will not interfere with the attainment of the statewide greenhouse gas (GHG) emission limits established under the CLCPA.[50] The SIRs amendments adopted in this Order will provide DER developers greater transparency and certainty with respect to utility interconnection costs, which will strengthen the distributed renewable energy market in New York State and enable more clean energy facilities to be deployed in furtherance of the State's climate goals. Accordingly, the actions taken in this Order will aid in the attainment of statewide GHG emissions limits.

The Commission also finds that approval of these cost estimating procedures will not disproportionately burden disadvantaged communities, consistent with CLCPA §7(3).[51] The adoption of the framework described herein simply implements improvements to the interconnection process in a neutral manner and does not involve the approval of any facilities.

The Commission further notes that the action herein relates to "practices by Utilities concerning administration and management of utility functions," and therefore constitutes a Type II action under the State Environmental Quality Review Act

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[50] Climate Leadership and Community Protection Act (CLCPA), Chapter 58 of the Laws of 2020, Part JJJ. Section 7(2) of the CLCPA requires that State agencies, in considering and issuing permits, licenses, and other administrative approvals and decisions, "consider whether such decisions are inconsistent with or will interfere with the attainment of the statewide [GHG] emissions limits" established under Article 75 of the Environmental Conservation Law (ECL) and, if so, provide "justification as to why such limits/criteria may not be met, and identify alternatives or [GHG] mitigation measures to be required where a project is located."

[51] Section 7(3) of the CLCPA requires that State agencies, in considering and issuing permits, licenses, and other administrative approvals and decisions, "shall not disproportionately burden disadvantaged communities" as identified pursuant to ECL §75-0101(5).

(SEQRA).[52] Accordingly, the action is not subject to review under SEQRA.

CONCLUSION

For the reasons discussed in the body of this Order, we adopt the SIRs modifications reflected in Appendix C and direct the Utilities to submit tariff amendments incorporating those provisions, on not less than 14 days' notice, to become effective October 1, 2026. As this Order was the subject of substantial public process, the requirements for newspaper publication of the tariff amendments will be waived.

The Commission orders:

1. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall file tariff amendments to incorporate into their electric tariffs the revised Standard Interconnection Requirements set forth in Appendix C, as discussed in the body of this Order. These tariff amendments shall be filed on not less than 14 days' notice, to become effective on October 1, 2026.

2. The requirements of Public Service Law §66(12)(b) and 16 NYCRR §720-8.1, related to newspaper publication of the tariff amendments directed in Ordering Clause 1, are waived.

3. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and

[52] See 16 NYCRR §7.2(b)(2).

Rochester Gas and Electric Corporation shall annually file data by March 31 of each year, beginning March 31, 2027, indicating the number of business days taken to complete each Coordinated Electric System Interconnection Review completed in the prior calendar year, as discussed in the body of this Order.

4. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall publish their cost matrices by March 31, 2027, and annually update their matrices in consultation with the ITWG by March 31, as discussed in the body of this Order.

5. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall file their data comparing cost estimates and actual project costs over the prior five calendar years, beginning March 31, 2027, and every year thereafter, as discussed in the body of this Order.

6. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall file a proposal to provide final reconciliation statements within 90 days of the effective date of this Order, as discussed in the body of this Order.

7. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation

d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall file a proposal for providing cost estimates at an increased level of confidence upon request, by January 15, 2027, as discussed in the body of this Order.

8. In the Secretary's sole discretion, the deadlines set forth in this Order may be extended. Any request for an extension must be in writing, must include a justification for the extension, and must be filed at least three days prior to the affected deadline.

9. Case 24-E-0415 shall be closed. Case 24-E-0621 shall be continued and all filings directed in this Order shall be made in Case 24-E-0621.

By the Commission,

(SIGNED)

MICHELLE L. PHILLIPS
Secretary

COMMENTS ON 2025 STAFF PROPOSAL

City of New York

In its comments, the City supports the Staff Proposal and suggests modifications to provide additional cost certainty to developers. The City notes that DERs are essential to the decarbonization of the grid and states that it is developing its own portfolio of distributed solar projects. The City agrees that developers should have visibility into utility costs and should receive notice of changes in cost in the interconnection process, to improve a developer's ability to make informed decisions. The City supports requiring the utilities to publish and update their cost estimating matrices. However, the City recommends that the annual updates be subjected to stakeholder review to verify their accuracy, and to a Staff or Commission approval process.

The City states that it does not support removing the 15% contingency from the CESIR cost estimate. The City argues that the contingency should be treated as a cap on the total amount utilities can charge developers, asserting that this approach would force the utilities to be more accurate in their cost estimating. The City notes that providing for revisions to cost estimates would address the problem of CESIR estimates becoming stale when project development is delayed.

Coalition for Community Solar Access (CCSA)

CCSA states that cost uncertainty is a significant barrier to building renewable energy projects in New York. The organization agrees that an annually updated cost matrix would improve the current process. However, CCSA does not support Staff's proposal to provide cost estimate updates twelve months after the CESIR and agrees with NYSEIA that having this information does not provide stability for developers to make investment decision. CCSA also agrees with NYSEIA that the 15%

contingency should be converted to a hard cap on developers' cost obligations. CCSA states that the utilities should be treated like contractors, who generally have responsibility for keeping to the agreed-on project budget.

GS Power Partners (GSPP)

GSPP supports NYSEIA's position and advises that utilities should not revise a CESIR estimate without the interconnection applicant's consent in order to provide greater certainty in payment obligations. GSPP expresses support for the intent behind Staff's proposal but notes that it does not sufficiently address cost certainty.

NYSEIA

NYSEIA asserts that improving cost estimating and cost certainty for distribution upgrades is necessary for achieving New York's policy objectives. NYSEIA agrees that the utilities should publish their cost matrices annually but states there is a need for stakeholders to evaluate the utilities' cost data prior to implementing the updates. NYSEIA also supports Staff's recommendation to tie cost estimates to the information provided with a utility's cost matrix. NYSEIA asks for clarification of Staff's proposal to modify language defining the scope of a cost estimate and offers alternative language. The organization supports Staff's proposal to require the applicant's consent to a CESIR revision. NYSEIA opposes removal of the contingency from the cost estimate and argues that doing so would lead to utilities incorporating excessive contingencies in their cost estimates, increasing developers' upfront costs. Finally, NYSEIA also opposes the proposal to update cost estimates for projects that are not in-service within twelve months because the information would "introduce new cost uncertainty."

RIC Energy (RIC)

RIC views Staff’s proposal as well-intended but urges the Commission to reject the proposal. RIC asserts that the role of Staff is to serve as a facilitator for the IPWG and that, “[i]t is not the intended process of the IPWG for [Staff] to independently submit policy proposals for consideration by the Commission based on policy conversations that take place in the working group.”[1] RIC notes that Staff did not modify its proposal based on stakeholder feedback and that there was a lack of consensus on the proposal amongst IPWG participants.

RIC suggests that Staff’s proposal to require utilities to update cost estimates if a project is not in service within 12 months does not adequately consider realistic project permitting timelines, which it indicates often exceed 12 months. RIC advises that utility cost estimates should be conducted anticipating a longer timeline for completing system upgrades. In addition, RIC opposes Staff’s proposal to require utilities to provide new cost estimates with revised CESIRs because of the potential for minor project design changes, which may have minimal impacts to the required system upgrades, to trigger a new cost estimate and associated payment obligation for the developer.

RIC objects to Staff’s proposed removal of the language containing contingencies in cost estimates to 15%. RIC advises that contingencies should be explicitly defined in the SIRs to protect developers from higher upfront costs for DER projects. RIC notes that neither the Utilities nor developers participating in the IPWG discussion advocated for striking the contingency language from the SIRs. RIC also cautions that adopting Staff’s proposed modifications would provide increased

[1] RIC Comments, p.2.

transparency into how the cost matrix figures are determined but would decrease transparency into how the cost matrix is applied to individual projects.

Utilities

The Utilities urge the Commission to defer consideration of Staff's proposal until it can consider the proposal alongside NYSEIA's Cost Cap Petition. The Utilities express concern regarding the proposal to restrict CESIR updates. The Utilities reference a recent analysis indicating that the time period between CESIR completion and interconnection for projects with an installed capacity exceeding 300 kilowatts ranged from approximately 2.75 years to 4.5 years. Over such timeframes, the Utilities note, significant changes may occur in system configuration, supply chains, and material pricing, with the potential to significantly impact the scope and costs of the upgraded needed for interconnection. Consequently, the Utilities recommend that the Commission retain the language in the SIRs authorizing utilities to provide updated cost estimates upon completion of design work if the scope has changed since the CESIR estimate was provided. Alternatively, the Utilities recommend that the SIRs require utilities to provide updated estimates where the earlier CESIR may no longer be valid due to unanticipated system configuration changes.

The Utilities suggest that requiring consent from interconnection applicants before utilities can revise cost estimates to reflect changes to the system configuration for resiliency or reliability upgrades would likely shift the costs to utilities' electric customers because applicants are unlikely to provide consent. The Utilities also caution that restricting CESIR updates could result in applicants pursuing local permitting for a scope that is no longer valid, absent an alternative mechanism to communicate a change in configuration.

The Utilities support Staff’s proposal to formalize the cost matrix process developed at the ITWG. However, the Utilities note that the matrices are not intended to include all items and equipment needed for upgrades, which are customized to the location, project specifics, and distribution and substation infrastructure, amongst other inputs that are not captured sufficiently by the matrix. The Utilities recommend that Staff’s proposed SIRs language be modified to indicate that ““...cost estimates provided in the CESIR shall be based on the same cost information used to develop the cost matrix.”[2] The Utilities also recommend that that annual updates occur by March 31 in order to include data from the full prior calendar year.

In addition, the Utilities express support for the use of contingencies as a best practice for cost estimating and managing unforeseen risks encountered during construction.

COMMENTS ON 2026 STAFF PROPOSAL

City of New York

The City supports Staff’s proposal to increase transparency in interconnection cost estimating and recommends that the Commission adopt additional measures to further promote transparency and efficiency. The City recommends that Staff conduct annual audits of utilities’ cost estimates and final expenses. In addition, the City urges the Commission to impose an interconnection cost cap to provide greater cost certainty to developers, as it explains that upgrade costs are frequently a key component of financial modeling for DER projects. The City

[2] Utilities’ Comments, p. 6.

recognizes that costs may change as projects progress, but advises that the changes must be reasonable and predictable.

As background, the City highlights its commitment to carbon neutrality by 2050 and its goal to deploy 1,000 megawatts (MW) of solar energy by 2030, with 150 MW of solar on city-owned property by 2035. The City points out that DERs are an essential element of decarbonizing the electric grid, particularly in New York City, with space and siting are major constraints. The City indicates that it is pursuing its own portfolio of distributed solar projects. However, the City observes that DER development is facing increasing headwinds, including interconnection costs, as project scopes grow become more complex and DER saturation increases, while limited details are providing to developers about escalating costs.

NYSEIA

NYSEIA supports Staff's proposal to formalize the cost matrix and update it annually. However, NYSEIA recommends incorporating additional elements from its February 2025 Petition to more comprehensively address issues involving cost estimation and actual costs. NYSEIA contends that the utilities should be required to use the same figures in their current cost matrix when providing project-specific cost estimates because the unit price of major items should not vary within the same year, though NYSEIA acknowledges that the matrix does not account for project-specific nuances that could influence estimates. NYSEIA suggests that all elements in the cost matrix be itemized, clearly defined, and uniform across the utilities. More specifically, NYSEIA proposes that cost estimates include equipment type, quantity/units, technical specifications, and estimated internal and subcontract labor costs with assumptions disclosed, such as whether overtime or base rates are applied. Relatedly, NYSEIA asserts that overtime and contractor cost adjustments should only be allowed upon written approval by a developer when the developer requests an accelerated timeline or work outside the defined scope.

To promote accuracy in estimates, NYSEIA asks the Commission to authorize a formal regulatory process to update cost matrices, including public review, discovery, and public comment before the matrices are adopted by the Commission. NYSEIA explains that such transparency will enable Staff and other stakeholders to identify discrepancies in the utilities' costs. NYSEIA also suggests that the Commission shield DER customers from cost volatility by preventing utilities from reissuing cost estimates within three years unless an updated estimate is requested by the interconnection customer. NYSEIA advises that a 15% contingency should be limited to material and labor costs because those costs are most likely to change based on external factors, while other costs, such as overhead, are highly predictable.

NYSEIA puts forth several recommendations to provide increased transparency in project reconciliation statements. Specifically, NYSEIA proposes that the Commission require utilities to explain why final costs deviated from estimates; include itemized costs, with a granular breakdown of all equipment units, internal utility work hours, and contractor work hours differentiating internal and contractor labor costs; proactively inform developers of costs that are likely to result in overruns and only incur such costs upon written approval from developers; and prohibit utilities from recovering increased overhead costs for equipment or labor unless the utility can itemize and directly attribute any overhead increase to the specific project.

RIC Energy

RIC generally agrees with Staff that there is a need for greater transparency in interconnection costs but believes that Staff's proposal does not sufficiently address the practices and methodologies used by the utilities. RIC suggests that the Commission prescribe a methodology for the utilities to use in calculating costs and direct the utilities to file a report detailing their compliance with such methodology. RIC proposes that the methodology should assume a 36-month project development timeline to more accurately account for expected timelines and estimate costs accordingly. RIC further recommends that the costs in the matrix be itemized to show material costs, utility labor costs, and contracted labor costs as individual line items.

RIC notes that labor costs are comprising increasingly large percentages of overall interconnection costs in recent years, yet developers are unable to view utilities' lists of contractors and rates charged by those contractors. RIC acknowledges that divulging such information may be prohibited under the utilities' vendor agreements but maintains that withholding basic cost breakdowns from developers responsible for paying such costs is an unreasonable business practice. RIC also asserts that the costs of specific interconnection activities are inconsistent across utilities and that utilities' cost increases exceed the cost increases seen in economic data, highlighting the need for increased transparency and accuracy in utility cost estimates.

RIC also opines that the value of increased transparency provided by the cost matrix will be limited unless there is corresponding transparency in final reconciliation statements. RIC recommends that final reconciliations be itemized and include justification for any cost overruns.

Utilities

The Utilities support Staff's proposal to increase transparency while recommending a modification to host the matrices on the ITWG webpage and include the obligation in the SIRs to publish and annually update the matrices. The Utilities note that publishing the matrices on the ITWG webpage rather than embedding the matrices within the SIRs would allow updates to be made promptly without necessitating a formal action by the Commission and preserve the SIRs as a stable procedural framework that is not frequently updated. The Utilities also explain that the ITWG is already used as a repository for technical interconnection documents and is regularly accessed by developers and other stakeholders.

In addition, to avoid potential misinterpretation of Staff's proposal for the utilities to "begin using the updated cost matrices in their cost estimating work," the Utilities suggest that the SIRs clarify that the matrices are a reference for common categories and typical costs, but that the utilities will develop detailed, project-specific good-faith estimates tailored to engineering design and system conditions. The Utilities note that cost matrices are broad and that actual project costs for specific projects will vary significantly, depending on grid conditions at the point of interconnection and project specifics, including unanticipated site conditions, permitting, land acquisition delays, construction delays, global supply chain impacts, labor contracts, and procurement contracts, among other things.

COMMENTS ON 2025 NYSEIA PETITION

A majority of commenters, representing DER developers and allied organizations, express support for the proposals in

NYSEIA's petition (collectively, the Industry Supporters).[3] The Industry Supporters concur in NYSEIA's request for an increase in the level of detail in the CESIR cost estimates including itemized equipment-level cost breakdowns with labor, materials, and contingency for distribution upgrades included. They state that these details will provide greater transparency and clarify what expenses the interconnection customers are paying for. The Industry Supporters agree that the Commission should establish a hard cap on utility cost overruns by limiting upward cost adjustments to 115% of the CESIR cost estimates. The Industry Supporters suggest this approach provides the utility with a reasonable contingency of 15% and manages the cost to complete the distribution system upgrades. They also recommend establishing an annual cost matrix filing requirement to provide DER developers with greater cost transparency and insight into cost increases. Finally, the Industry Supporters agree with the request that the Commission require utilities to itemize the final costs for all distribution upgrades and to explain any variances in excess of the 15% cap.

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[3] Ascent Renewables LLC; Blue Redwood; Bluewave; Carson Power, LLC; Catalyze; the City of New York; the Coalition for Community Solar Access; Distributed Sun LLC; EDF power solutions; Encore Renewable Energy; Finlo, LLC; Friends of Columbia Solar; Gigaflow, Inc.; Greenwood Sustainable Infrastructure; GridEdge Networks, Inc.; Kendall Sustainable Infrastructure; Lodestar Energy, LLC; Montante Solar; New Energy Equity, LLC; New Leaf Energy; New York Battery and Energy Storage Technology Consortium; New Yorkers for Clean Power; Nexamp; Norbut Solar Farms, LLC; Pratt Center for Community Development; Radial Power, LLC; RIC Energy; Scale Microgrid Solutions; Solar Energy Industries Association; Sunkeeper Solar Electric LLC; Sustainable PR; Third Act Upstate New York; and Vote Solar express support for NYSEIA's Cost Cap Petition.

NYSEIA in its comments requests that the estimates provided by the utility include the quantity and the units of any material utilized, technical specifications where appropriate and the internal and subcontracted labor rates. The Solar Energy Industries Association (SEIA) points out its agreement with NYSEIA in its disallowance of any indirect costs that are not itemized by the utility. SEIA adds that absent the use of detailed costs described herein, developers would need to include unspecified costs in the risk to offset the risk of potential cost overruns resulting in higher development costs.

NYSEIA further points out that although the utility controls what equipment is needed and the cost and quantity of labor required, the mismatch is that the developer is the one who pays the costs, but the utility is the party who controls costs. NYSEIA therefore suggests the Commission impose a cost cap of 115% of the original CESIR cost estimate and also posits that reducing the frequency and magnitude of cost overruns will likely lead to lower actual interconnection costs for DERs but also for utility scale projects and grid upgrades in general, thus reducing ratepayer expenses in these areas.

NYSEIA states that passing on "retroactive" price increases of 30% - 100% of the original CESIR estimate to developers is unacceptable. NYSEIA adds that if market participants can't rely on original utility estimates, developers will price that risk into the expected value of the project, which in turn will raise the cost of the NY-Sun program incentives that developers seek. These cost premiums will be applied even for projects for which there is no subsequent CESIR estimate.

In its comments, SEIA supports requiring the utility to pay the incremental costs beyond 115% of the original estimate, which should provide impetus to the utility to keep project costs within the 115% cap.

SEIA states that if the Commission adopts the control mechanisms above, it should also adopt rules that dissuade utilities from using inflated CESIR estimates to cover their expenses in excess of 115%, as explained above. In defense of these proposed rules, SEIA warns that consistently overestimated CESIR costs could negatively affect distributed solar costs and deployment in New York State and artificially raise DER prices and make projects appear more expensive to interconnect than they would actually be, resulting in more otherwise eligible projects would not move forward with inflated CESIR costs.

Lastly, SEIA warns of the challenges surrounding the federal regulatory environment and the necessity of reducing soft costs in policy areas under state control. The uncertainty and impact surrounding the key federal tax incentives including the ITC is still evident, but the cost proposals recommended by NYSEIA would lower the cost and reduce risk of solar projects in New York to move the state ahead in its clean energy goals.

The City of New York supports the NYSEIA proposal in part but recommends some modifications to provide additional efficiency and transparency. The City repeats its commitment to carbon neutrality by 2050 and its renewable energy goals including the deployment of 1,000 MW of solar citywide by 2030 and emphasizes that siting DERs are an essential component of achieving these goals.

The City emphasizes that while solar DERs have been successful to date in New York State, the increasing interconnection costs with less detail provided by the utilities in their estimates are a serious issue. It therefore supports the additional transparency and proposed itemized final reconciliation statement recommended by NYSEIA.

Utilities

In their comments on NYSEIA's petition, the Utilities offer both general observations and specific responses to NYSEIA's assertions. The Utilities contest NYSEIA's claim that utility cost increases are eroding the integrity of the interconnection process. The Utilities state that rising costs have a broad impact and are not exclusive to DER interconnections. They point to several factors that affect the industry, such as supply chain challenges, increasing material costs, and the impact of tariffs. They also argue that developer delays are a cause of the cost increases NYSIEA criticizes, explaining that "CESIR estimates as they exist today cannot anticipate multi-year delays, due to site work complexities and/or municipal permitting constraints unknown pre-CESIR."[4] They provide a summary of the time developers needed to complete projects after receiving their CESIRs, based on 2025 data for projects larger than 300 kW. The data, according to the Utilities, show that developers' time to interconnection ranged from about 2.75 years to over 4.5 years after the CESIR step. The Utilities state that significant changes in material pricing can occur over such long time periods.

The Utilities do not support imposing a cap on developer interconnection cost responsibility. The Utilities state that such a cap would result in shifting the risk of cost increases to utility customers, which the Utilities argue would be contrary to longstanding cost causation principles. The Utilities cite the Commission's determination in the REV

[4] Utilities' Comments, p. 3.

proceeding recognizing that DER customers "pay the utility fair value for the services provided by grid connectivity and utilities should pay the customer fair market value for services provided by the customer."[5] A policy where the utility could recover interconnection costs from DER applicants would put pressure on the utility's budget for meeting other system needs, such as reliability and resiliency projects.

The Utilities also argue that cost caps could lead to utilities incorporating risk mitigation factors into cost estimates, with the likely result of increasing those estimates and deposit amounts. They further state that the need to manage under a cap could also require the utilities to take more time to develop more accurate cost estimates and would in general reduce their flexibility to respond to project-specific issues. According to the Utilities, the possible short-term gains of imposing a cap would be outweighed by the higher upfront cost and the need to extend interconnection timelines.

The Utilities state that other measures, not involving a cost cap, could be applied to reduce uncertainty.[6] These include imposing additional requirements on developers to provide more project details and allowing a utility more time to conduct site visits and identify constructability issues or environmental features that may affect the project design, before providing estimates. The Utilities acknowledge NYSEIA's request that the Commission establish the AACE Class 3 estimating standard in the SIRs but argue that the existing CESIR timeframe – 60 business days - does not allow enough time to produce estimates that would meet that standard. In

[5] Id., p. 9.

[6] The Utilities point to submissions they made in the Metrics Proceeding discussing the same issues.

particular, they state that the AACE standard would require site visits and several months of additional time to complete more detailed designs before developing costs. The Utilities suggest the collaborative working groups could be the forum for discussion of the pros and cons of establishing a new standard for cost estimating.

In response to NYSEIA's concern that developers have no way of controlling cost overruns, the Utilities state that a self-build option, under which developers would control the contracting and performance directly, could be offered. National Grid has recently implemented a self-build option in accordance with the terms of the Joint Proposal and rate plan adopted by the Commission last year.[7] This self-build option is eligible as of March 2026 and would serve as a good example of lessons learned for deployment elsewhere in the State by other utilities. They caution that efforts to introduce such a program in other jurisdictions have not shown great results but that a workable option could be developed in the ITWG.

The Utilities support establishing an annual process for updating the distribution upgrades cost matrix and recommend that the Commission require the use of the cost matrix information as the basis for CESIR cost estimates. The Utilities believe the current practice, under which the cost matrices are published on the utilities' DG portals, is sufficient and that the cost matrix data does not need to be filed with the Commission. The Utilities state confidentiality concerns in support of this position. The companies also support

[7] Case 24-E-0322 et al., National Grid Rate Proceeding, Order Adopting Terms of Joint Proposal and Establishing Rate Plans (issued August 14, 2025), pp. 56-57.

continuing to use of the IPWG and ITWG as the forums for annual cost matrix updates.

The Utilities object to NYSEIA's request to remove overhead costs from cost estimates as they assert it would inappropriately burden electric customers. They explain that they routinely allocate overheads to projects as required by the Uniform System of Accounts, such that each "job" bears "its equitable proportion of such costs."[8] The Utilities state that it is consistent with cost causation principles for DER developers, not ratepayers, to pay the utility overhead charged to their projects.

The Utilities also respond to the NYSEIA's request that the Commission direct the companies to provide a detailed accounting of how a developer's upgrade funds were spent within 60 business days of giving the customer permission to operate. They explain that the 60-business day period is insufficient to allow for an accurate accounting for all charges, resulting in developers not always paying the full costs attributable to their projects. The Utilities further note that the time period does not align well for projects subject to the Commission's rules for cost-sharing. The Utilities support continuing discussions in the ITWG on improvements to the cost reconciliation process.

Finally, the Utilities state that an annual audit of utilities' cost estimates and final costs is not necessary. They point out that each of them is subject to a periodic management audit by the Commission, in addition to prudency reviews conducted in rate cases. They suggest that the mediation contemplated in the standard interconnection contract is a

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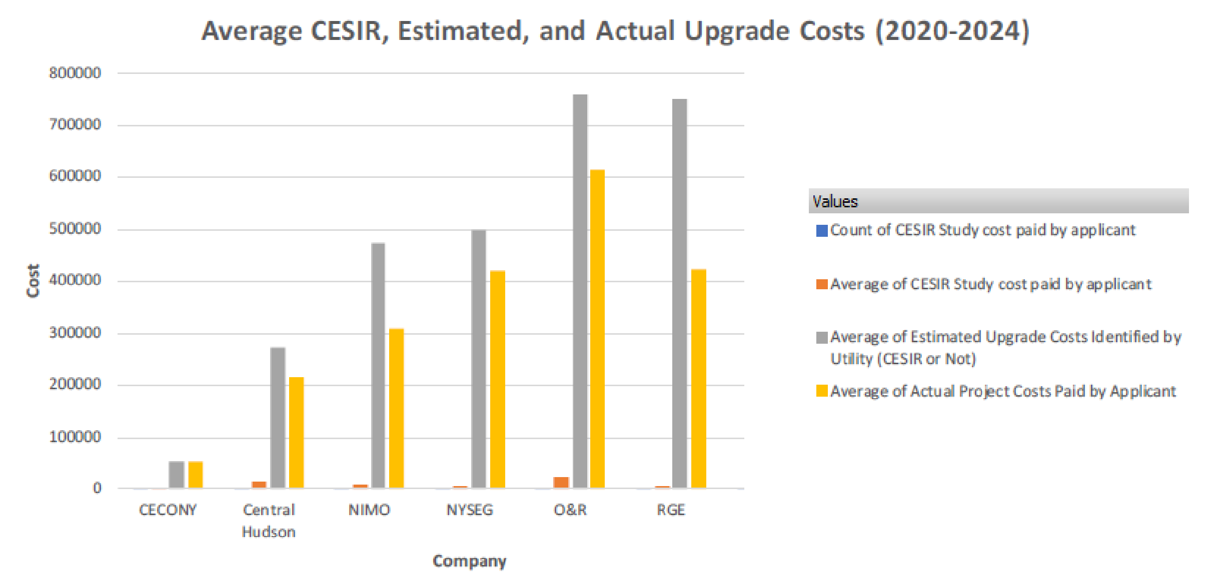
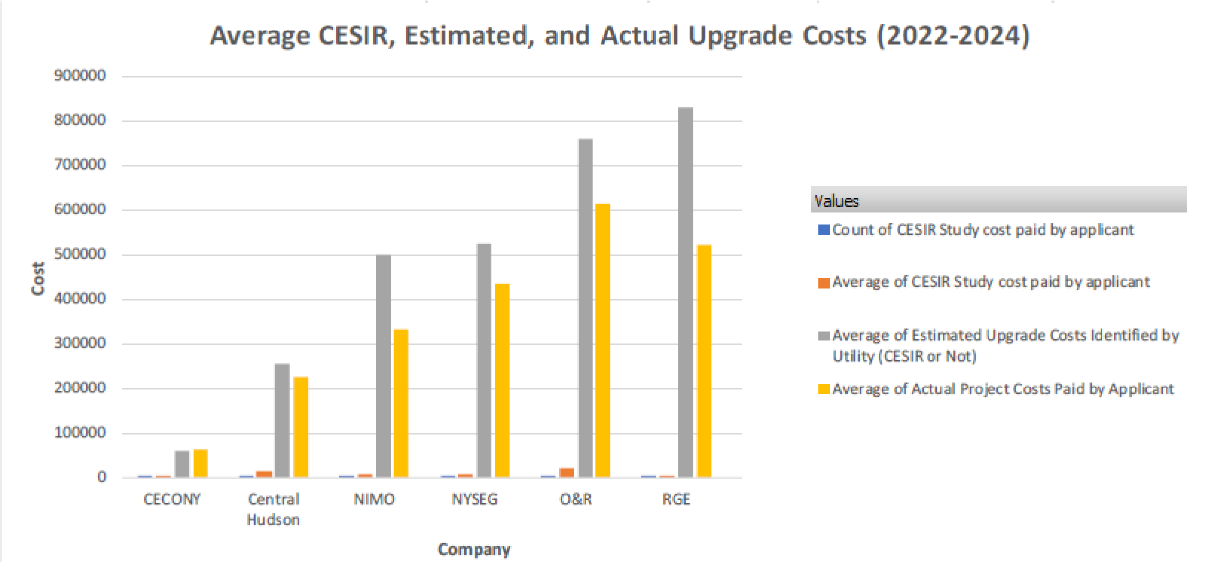
[8] Utilities' Comments, pp. 9-10.

sufficient mechanism for addressing cost disputes. Further, the Utilities argue that improved estimating and reconciliation and the publication of the cost matrices mitigate NYSEIA’s concerns for transparency and certainty.

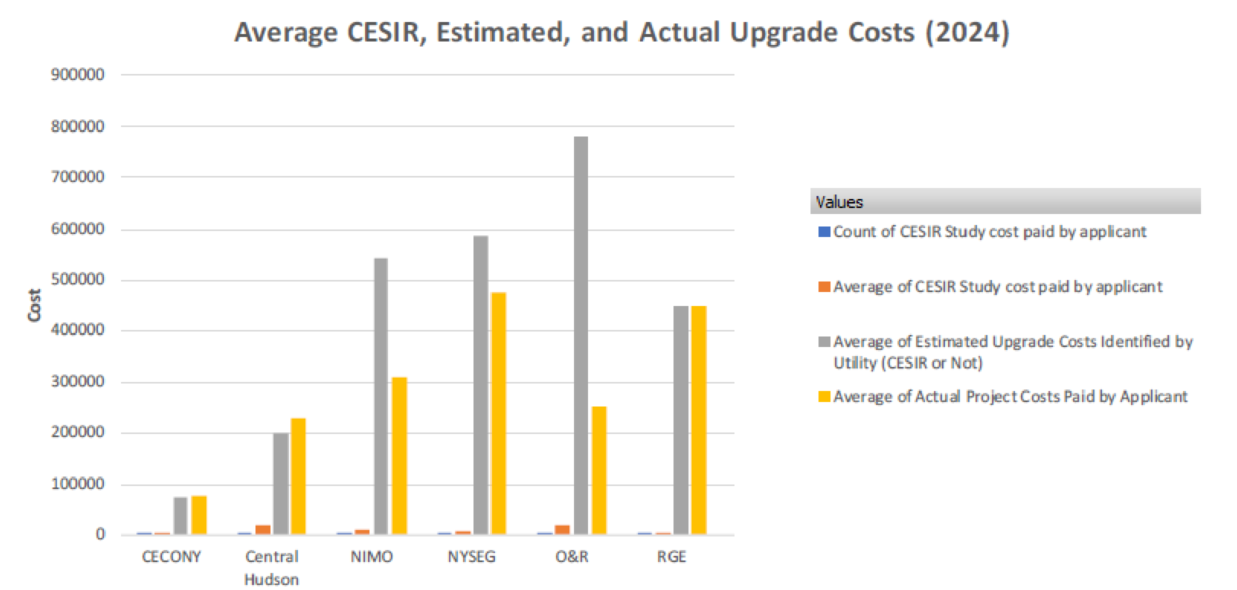
FEBRUARY 26, 2025 ITWG CESIR COST ANALYSIS



Company	Count of CESIR Study cost paid by applicant	Average of CESIR Study cost paid by applicant	Average of Estimated Upgrade Costs Identified by Utility (CESIR or Not)	Average of Actual Project Costs Paid by Applicant
CECONY	304	$ 3,929.58	$ 52,773.69	$ 53,943.68
Central Hudson	11	$ 15,059.86	$ 273,624.35	$ 214,997.42
NIMO	190	$ 9,148.42	$ 473,102.37	$ 309,461.42
NYSEG	74	$ 6,486.50	$ 497,728.93	$ 420,057.27
O&R	6	$ 22,095.00	$ 758,490.92	$ 614,525.35
RGE	13	$ 5,192.31	$ 750,871.77	$ 423,321.34



Company	Count of CESIR Study cost paid by applicant	Average of CESIR Study cost paid by applicant	Average of Estimated Upgrade Costs Identified by Utility (CESIR or Not)	Average of Actual Project Costs Paid by Applicant
CECONY	254	$ 3,953.05	$ 60,697.97	$ 62,098.28
Central Hudson	9	$ 15,653.27	$ 256,047.96	$ 227,317.79
NIMO	175	$ 9,330.86	$ 500,278.76	$ 332,740.17
NYSEG	66	$ 6,666.67	$ 524,805.83	$ 436,152.74
O&R	6	$ 22,095.00	$ 758,490.92	$ 614,525.35
RGE	11	$ 5,227.27	$ 830,863.00	$ 521,012.30



Company	Count of CESIR Study cost paid by applicant	Average of CESIR Study cost paid by applicant	Average of Estimated Upgrade Costs Identified by Utility (CESIR or Not)	Average of Actual Project Costs Paid by Applicant
CECONY	119	$ 3,558.75	$ 73,462.85	$ 76,863.37
Central Hudson	2	$ 19,680.75	$ 197,967.90	$ 227,812.49
NIMO	96	$ 9,511.46	$ 541,029.63	$ 310,023.92
NYSEG	37	$ 7,432.43	$ 585,967.16	$ 475,282.41
O&R	3	$ 19,330.00	$ 781,708.83	$ 252,282.39
RGE	1	$ 5,000.00	$ 448,469.00	$ 448,469.00

New York State
Public Service Commission

New York State Standardized Interconnection Requirements and Application Process for New Distributed Generators and/or Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems

Effective: October 1, 2026

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Section I. Application Process

A. Introduction

This Standardized Interconnection Requirements and Application Process for New Distributed Generators and/or Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems (SIR) provides a framework for processing applications to:

- interconnect new distributed generation (DG) facilities with an alternating current (AC) generator nameplate rating of 5 MW or less aggregated on the customer side of the point of common coupling (PCC);
- interconnect new energy storage system (ESS) facilities with an AC inverter/converter nameplate rating of 5 MW or less aggregated on the customer side of the PCC that may be stand-alone systems or combined with existing or new DG (Hybrid Projects), however, maximum export capacity onto the utility distribution system is capped at an AC nameplate rating or AC inverter/converter nameplate rating of 5 MW; and,
- review any modifications affecting the interface at the PCC to existing DG and/or ESS facilities with an AC nameplate rating of 5 MW or less (aggregated on the customer side of the PCC) that have been interconnected to the utility distribution system, and where an existing contract between the applicant and the utility is in place.

Distributed Generation or Energy Storage Systems neither designed to operate, nor operating, in parallel with the utility's electrical system are not subject to these requirements. This document will ensure that applicants are aware of the technical interconnection requirements and utility interconnection policies and practices. This SIR will also provide applicants with an understanding of the process and information required to allow utilities to review and accept the applicants' equipment for interconnection in a reasonable and expeditious manner.

The time required to complete the process will reflect the complexity of the proposed project. Projects using previously submitted designs certified per the requirements of Section II.H, Equipment Certification, will move through the process more quickly, and several steps may be satisfied with an initial application depending on the detail and completeness of the application and supporting documentation submitted by the applicant. Applicants submitting systems utilizing certified equipment, however, are not exempt from providing utilities with complete design packages necessary for the utilities to verify the electrical characteristics of the generator systems, the interconnecting facilities, and the impacts of the applicants' equipment on the utilities' systems.

The application process and the attendant services must be offered on a non-discriminatory basis. The utilities must clearly identify their costs related to the applicants' interconnections, specifically those costs the utilities would not have incurred but for the applicants' interconnections. The utilities will keep a log of all applications, milestones met, and justifications for application-specific requirements. The applicants are to be responsible for payment of the utilities' costs, as provided for herein. Any unspent project analysis/study fees shall be applied forward to any subsequent analysis applicable to a given application/project.

All application timelines shall commence the next Business Day following receipt of information from the applicant or the utility. For purposes of determining the date of an applicant's payment, when a payment is required, fees paid by wire transfer shall be deemed paid on the day of the transfer, whereas fees paid by check shall be deemed paid on the day the check clears.

Staff of the Department of Public Service ("DPS Staff") will monitor the application process to ensure that applications are addressed in a timely manner. To perform this monitoring function, DPS Staff will meet periodically with utility and applicant representatives.

A glossary of terms used herein is provided in Section III.

B. Application Process Steps for Systems 50 kW or Less

Exception 1:

For inverter based systems above 50 kW up to 300 kW, applicants may follow the expedited application process outlined in this section provided that the inverter based system has been certified and tested in accordance with the most recent revision of UL 1741, including supplement B ("UL 1741 SB"), with settings as specified in the utility's technical requirements document, and the utility has approved the project accordingly. The utility has ten (10) Business Days upon receipt of the original application submittal to determine if the application is complete, project is eligible for the expedited process, and whether it is approved for interconnection if eligible for expedited process. The utility shall notify the applicant in writing of its findings upon review of the application. If the utility determines that the inverter based system is not eligible for the expedited application process, the applicant can:

1) Proceed with the remaining steps of Section I.C of the SIR (Systems above 50 kW up to 5 MW); or
2) request a review by DPS Staff.

Exception 2:

For non-inverter based system 50 kW or less, the applicant should be aware that additional information and review time may be required by the utility (refer to Step 3). The applicant must include the items required in Step 5 of the Application Process Steps for Systems above 50 kW up to 5 MW in its original application. This exception should not be considered the rule but used by the utility only in justified situations. Utilities are encouraged to use the expedited process whenever possible. The utility has ten (10) Business Days upon receipt of the original application submittal to determine if the application is complete, project is eligible for expedited process, and whether it is approved for interconnection if eligible for expedited process. The utility shall notify the applicant in writing of its findings upon review of the application. If the utility determines that the non-inverter based system is not eligible for the expedited application process, the applicant can:

1) Proceed with the remaining steps of Section I.C of the SIR (Systems above 50 kW up to 5 MW); or
2) Request a review by DPS Staff.

Exception 3:

For all systems 50 kW or less, that are proposed to be installed in underground secondary network areas, the applicant should be aware that additional information and review time may be required by the utility (refer to Step 3). In some cases, interconnection may not be allowed or approved. DG systems interconnected to underground secondary network systems can cause unique design issues and overall reliability problems for the utilities. For this reason, additional review and analysis may be needed on a case by case basis. The utility has ten (10) Business Days upon receipt of the original application submittal to determine if the application is complete, project is eligible for the expedited process, and whether it is approved for interconnection if eligible for expedited process. The utility shall notify the applicant in writing of its findings upon review of the application. If the utility determines that the DG system cannot be interconnected, the applicant can request a review by DPS Staff.

STEP 1: Initial Communication from the Potential Applicant

Communication could range from a general inquiry to a completed application.

STEP 2: The Inquiry is Reviewed by the Utility to Determine the Nature of the Project

Technical staff from the utility may discuss the scope of the interconnection with the potential applicant (either by phone or in person) and provide a copy of the SIR document and any utility specific technical specifications that may apply. A utility representative shall be designated to serve as the single point of contact for the applicant in coordinating the potential applicant's project with the utility.

STEP 3: Potential Applicant Files an Application

The potential applicant submits an application package in the name of the customer[1] to the utility. No application fee is required of the applicant for systems 50 kW or less. A complete application package will consist of all items detailed in Appendix F. Electronic submission of all documents via the Interconnection Online Application Portal ("IOAP") is required. The utility has ten (10) Business Days upon receipt of the original application submittal to determine if the application is complete, meets the SIR technical requirements in Section II, and/or approved for interconnection if all other requirements are met. The utility shall notify the applicant by email, fax, or other form of written communication. If the application is deemed not complete by the utility, the utility shall provide a detailed explanation of the deficiencies identified and a list of the additional information required from the applicant.

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1 Per the Community Distributed Generation Program Order (issued July 17, 2015, in Case 15-E-0082), the project sponsor shall submit the interconnection application to the electric utility for approval. The sponsor may be any single entity, including the generation facility developer, an energy service company (ESCO), a municipal entity such as a town or village, a business or not-for-profit corporation, a limited liability company, a partnership, or other form of business or civic association.

Once it has received the required information, the utility shall notify the applicant of the acceptance or rejection of the application within ten (10) Business days. If the applicant fails to submit the additional information to the utility within thirty (30) Business Days following the date of the utility's written notification, the application shall be removed from the queue and no further action on the part of the utility is required.

The utility's notification of acceptance to the applicant shall include an executed New York State Standardized Interconnection Contract and the applicant may proceed with the proposed installation. The utility shall also indicate in its response to the applicant whether or not it plans to witness the testing and verification process in person.

An application will be placed in each utility's interconnection inventory once it is accepted as complete. If the final acceptance as set out in Step 6 below is not completed within twelve (12) months as a result of applicant inactivity, the utility has the right to notify the applicant by U.S. first class mail with delivery receipt confirmation or via email that the applicant's project will be removed from the utility's interconnection inventory if the applicant does not respond within thirty (30) Business Days of the issue of such notification and provide a project status update and/or justification as to why the project should remain in the utility's interconnection inventory for an additional period of time.

With respect to an applicant proposing to install a system rated 25 kW or less, that is to be net- metered, if the utility determines that it is necessary to install a dedicated transformer(s) or other equipment to protect the safety and adequacy of electric service provided to other customers, the applicant shall be informed of its responsibility for the actual costs for installing the dedicated transformer(s) and other safety equipment. Appendix E sets forth the responsibility each applicant shall have with respect to the actual cost of the dedicated transformer(s) and other safety equipment.

STEP 4: System Installation

The applicant will install the DG system according to the utility accepted design and the equipment manufacturer's requirements. If there are substantive design variations from the originally accepted system diagram, a revised system diagram (and other drawings for non-inverter based systems) shall be submitted by the applicant for the utility's review and acceptance. All inverter based systems will be allowed to interconnect to the utility system for a period not to exceed two hours, for the sole purpose of ensuring proper operation of the installed equipment.

For net metered systems as defined in Section II.A.6, Metering, any modifications related to metering configurations to allow for net energy metering for residential, farm service and non-residential wind electric generating systems shall be completed by the utility within ten (10) Business Days of either notification to the utility that the installation has been completed and inspected, or a request for a verification test, whichever comes first. If the utility requires inspection of the new metering configuration installation, such inspection shall be completed within the ten (10) Business Days allotted for the new meter installation.

STEP 5: The Applicant's Facility is Tested in Accordance with the Standardized Interconnection Requirements

Verification testing will be performed by the applicant in accordance with the written verification test procedure specified in Appendix F. If the utility requested to witness the testing and verification process in person as required in Step 3, the applicant shall provide a written letter of notification to the utility that the system installation is completed, including any applicable inspections and authorization. After receipt of notification, the verification testing will be performed within ten (10) Business Days, at a mutually agreeable time. If the utility has opted not to witness the test, the applicant will send the utility within five (5) Business Days of completion of such tests a written notification certifying that the system has been installed and tested in compliance with the SIR, the utility-accepted design and the equipment manufacturer's instructions. The applicant's facility will be allowed to commence parallel operation upon satisfactory completion of the tests in Step 5. The applicant must have complied with, and must continue to comply with, all contractual and technical requirements.

STEP 6: Final Acceptance

Within five (5) Business Days of receiving the written notification of successful test completion from Step 5, the utility will issue to the applicant a formal letter of acceptance for interconnection. Within five (5) Business Days of the completion of the on-site verification, the utility will issue to the applicant either a formal letter of acceptance for interconnection or a detailed explanation of the deficiencies in the system.

C. Application Process Steps for Systems above 50 kW up to 5 MW

If, at any point in its review of an application, the utility determines that the project may benefit from or require a Qualifying Upgrade, the procedures of Appendix E shall apply.

For inverter based systems above 50 kW up to 300 kW, certified and tested in accordance with the most recent revision of UL 1741, including supplement B (UL 1741 SB), and with settings as specified in the utility's technical requirements document, applicants and utilities are encouraged, but not required, to use the expedited application process (Section I.B).

Exception 1: For all systems 50 kW up to 5 MW that are proposed to be installed in underground secondary network areas, the applicant should be aware that a Coordinated Electric System Interconnection Review (CESIR) may be required by the utility, based on each utility's specific technical requirements and design considerations on a case-by-case basis. In some cases, interconnection may not be allowed or approved. DG systems interconnected to underground secondary network systems can cause unique design issues and overall reliability problems for the utilities. The utility has ten (10) Business Days upon receipt of the original application submittal and payment to determine if the application is complete and whether it is eligible for interconnection. The utility shall notify the applicant in writing of its findings upon review of the application. If the utility determines that the DG system cannot be interconnected or requires additional information be submitted and/or additional review time is needed, the applicant can:

1) Work with the utility on an appropriate timeframe and approval schedule agreeable to both parties; or

2) request a review by DPS Staff.

STEP 1: Initial Communication from the Potential Applicant.

Communication could range from a general inquiry to a completed application.

STEP 2: The Inquiry is Reviewed by the Utility to Determine the Nature of the Project.

Technical staff from the utility may discuss the scope of the interconnection with the potential applicant (either by phone or in person) and shall provide a copy of the SIR and any utility specific technical specifications that may apply. A utility representative shall be designated to serve as the single point of contact for the applicant in coordinating the potential applicant's project with the utility. At this time the applicant may also request that a Pre-Application Report (see Appendix D herein) be provided by the utility. The applicant shall provide a non-refundable fee of $750 with its request for completion of the Pre-Application Report. The Pre-Application Report shall be provided to the applicant within ten (10) Business Days of receipt of the form and payment of the fee. The Pre-Application Report will be non-binding and shall only provide the electrical system data and information requested that is readily available to the utility. Should the applicant formally apply to interconnect their proposed DG project within fifteen (15) Business Days of receipt of the utility's Pre-Application Report, the $750 will be applied towards the application fee in Step 3.

STEP 3: Potential Applicant Files an Application

The potential applicant submits an application to the utility in the name of the customer.[2] A complete application package will consist of all items detailed in Appendix F. Electronic submission of all documents via the Interconnection Online Application Portal (IOAP) is required. If a Pre-Application Report has been provided to the customer, and an application is received by the utility within fifteen (15) Business Days of the date of issue of the Pre-Application Report, a $750 credit will be applied towards the application fee. If an application is received by the utility later than fifteen (15) Business Days from the date of issue of the Pre-Application Report, the $750 fee will not be applied to the application fee. If the applicant proceeds with the project to completion, the application fee will be applied as a payment to the utility's total cost for interconnection, including the cost of processing the application.

The utility shall review the application to determine whether it is complete in accordance with Appendix F, and whether any additional information is required from the applicant. The utility shall notify the applicant in writing within ten (10) Business Days following receipt of the application and the application fee. If the application is not complete, the utility shall provide a detailed explanation of the deficiencies and provide a list of additional

[2] Per the Community Distributed Generation Program Order (issued on July 17, 2015, in Case 15-E-0082), the project sponsor shall submit the interconnection application to the electric utility for approval. The sponsor may be any single entity, including the generation facility developer, an energy service company (ESCO), a municipal entity such as a town or village, a business or not-for-profit corporation, a limited liability company, a partnership, or other form of business or civic association.

information needed to the applicant. The utility shall notify the applicant by email, fax, or other form of written communication. The utility review at this stage is limited to the determination of completeness from an administrative perspective and does not mean the application has also received approval from an engineering perspective. The utility may require supplemental materials and information for purposes of performing a CESIR.

If the applicant fails to submit all items required by Appendix F, or to provide additional information identified by the utility within thirty (30) Business Days following the date of the utility's notification, the application shall be deemed withdrawn and no further action on the part of the utility is required.

A completed application shall be placed in the utility's interconnection queue.

If the required documentation is presented in this step, it will allow the utility to move to Step 4 and perform the required reviews and allow the process to proceed as expeditiously as possible.

The utility will refund any advance payments for services or construction not yet completed should the applicant be removed from the utility's interconnection inventory. If the costs incurred by the utility exceed the advance payments made by the applicant prior to removal from the interconnection inventory, the applicant will receive a bill for any balance due to the utility.

STEP 4: Utility Performs Preliminary / Supplemental Screening Analysis and Develops a Cost Estimate for the Coordinated Electric System Interconnection Review (CESIR) if required

The utility shall perform a Preliminary Screening Analysis of the proposed system interconnection utilizing the technical screens A through F detailed in Appendix G. The Preliminary Screening Analysis shall be completed and a written response detailing the results of each screen and the overall outcome of the Preliminary Screening Analysis shall be sent to the applicant within fifteen (15) Business Days of the completion of Step 3. Depending on the results of the Preliminary Screening Analysis and the subsequent choices of the applicant, the following process(es) will apply:

If the Preliminary Screening Analysis finds that the applicant's proposed system passes all of the relevant technical screens (i.e., Screens A through F) and is in compliance with the Interconnection Requirements outlined in Section II, and there are no requirements for Interconnection Facilities or Distribution Upgrades, the utility will return a signed and executed New York State Standardized Interconnection Contract to the applicant. The applicant will sign and return the contract within 15 Business Days after receipt from the utility and proceed with the interconnection process.

If the Preliminary Screening Analysis finds that the applicant's proposed system cannot pass all of the relevant technical screens (i.e., Screens A through F), the utility shall provide the technical reasons, data and analysis supporting the Preliminary Screening Analysis results in writing. The applicant shall notify the utility within ten (10) Business Days following such notification whether to (i) proceed to a Preliminary Screening Analysis results meeting, (ii) proceed to Supplemental Screening Review, (iii) proceed to a full CESIR, or (iv) withdraw the Interconnection Request. If a cost estimate for the CESIR is not provided with the Preliminary

Screening Analysis results, the utility shall provide one within five (5) Business Days of a request from the applicant. If the applicant opts to proceed to a full CESIR, the utility shall provide an invoice for the CESIR fee to the applicant within ten (10) Business Days of receipt of the applicant's notification. The applicant shall have ten (10) Business Days from receipt of the invoice to pay the CESIR fee. If the applicant fails to meet either the notification or the payment deadline, the application shall be removed from the queue and no further action on the part of the utility is required.

i. If the applicant chooses to proceed to a Preliminary Screening Analysis results meeting and modifications that obviate the need for Supplemental Screening Analysis are identified, and the applicant and the utility agree to such modifications, the utility shall return a signed and executed New York State Standardized Interconnection Contract within fifteen (15) Business Days of the Preliminary Screening Analysis results meeting if no Interconnection Facilities or Distribution Upgrades are required. The applicant will sign and return the contract within 15 Business Days after receipt from the utility and proceed with the interconnection process.

   If Interconnection Facilities or Distribution Upgrades are required and agreed to, the utility shall provide the applicant with a non-binding cost estimate of any Interconnection Facilities or Distribution Upgrades within fifteen (15) Business Days of the Preliminary Screening Analysis results meeting. The applicant will pay the cost estimate as provided in Section I-D.

   If the applicant chooses to proceed to a Preliminary Screening Analysis results meeting and modifications that obviate the need for Supplemental Analysis are not identified and agreed to, the applicant shall notify the utility within ten (10) Business Days of the meeting of their intention to (i) proceed to Supplemental Screening Analysis, (ii) proceed to a full CESIR, or (iii) withdraw the application. If the applicant fails to notify the utility of their decision by this deadline, the application shall be removed from the queue and no further action on the part of the utility is required.

ii. Applicants that elect to proceed to Supplemental Screening Analysis shall provide a nonrefundable fee of $2,500 with their response; however actual costs up to a maximum of $5,000 will be billable to the applicant upon reconciliation of utility costs as defined in Step 11 or exit from the interconnection queue. The utility shall complete the Supplemental Screening Analysis within twenty (20) Business Days, absent extraordinary circumstances, following authorization and receipt of the fee. If the Supplemental Screening Analysis finds that the applicant's proposed system passes all of the relevant technical screens (i.e., screens G through I) and is in compliance with the Interconnection Requirements outlined in Section II, then there are no requirements for Interconnection Facilities or Distribution Upgrades. Thus, the utility will return a signed and executed New York State Standardized Interconnection Contract to the applicant within fifteen (15) Business Days of providing the applicant the results of the Supplemental Screening Analysis. The applicant will sign and return the contract within fifteen (15) Business Days after receipt from the utility and proceed with the interconnection process.

If the Supplemental Screening Analysis finds that the applicant's proposed system cannot pass all of the relevant technical screens (i.e., Screens G through I), the utility shall provide the technical reasons, data, and analysis supporting the Supplemental Screening Analysis results in writing. The applicant shall notify the utility within ten (10) Business Days following such notification whether to (i) proceed to a Supplemental Screening Analysis results meeting, (ii) proceed to a full CESIR, or (iii) withdraw the application. If the applicant fails to notify the utility of their decision by this deadline, the application shall be removed from the queue and no further action on the part of the utility is required.

i. If the applicant chooses to proceed to a Supplemental Screening Analysis results meeting and modifications that obviate the need for a CESIR are identified, and the applicant and the utility agree to such modifications, the utility shall return a signed and executed New York State Standardized Interconnection Contract within fifteen (15) Business Days of the Supplemental Screening Analysis results meeting if no Interconnection Facilities or Distribution Upgrades are required. The applicant will sign and return the contract within fifteen (15) Business Days after receipt from the utility and proceed with the interconnection process.

   If Interconnection Facilities or Distribution Upgrades are required and agreed to, the utility shall provide the applicant with a non-binding cost estimate of any Interconnection Facilities or Distribution Upgrades within fifteen (15) Business Days of the Supplemental Screening Analysis results meeting. The applicant will pay the cost estimate as provided in Section D.

ii. If the applicant chooses to proceed to a Supplemental Screening Analysis results meeting and modifications that obviate the need for a CESIR are not identified and agreed to, the applicant shall notify the utility, within ten (10) Business Days of the meeting, of their intention to proceed to a full CESIR or withdraw the application. If the applicant fails to notify the utility of their decision by this deadline, the application shall be removed from the queue and no further action on the part of the utility is required.

iii. If the applicant decides to proceed to a CESIR after the Supplemental Screening Analysis results meeting, or if the applicant chooses at any time in the above process to proceed directly to a CESIR, the utility shall provide a cost estimate for the CESIR, if not already provided with preliminary analysis results, within five (5) Business Days of a request from the applicant. If the applicant opts to proceed to a full CESIR, the utility shall provide an invoice for the CESIR fee to the applicant within ten (10) Business Days of receipt of the applicant's notification. The applicant shall have ten (10) Business Days from receipt of the invoice to pay the fee. If the applicant fails to meet the payment deadline, the application shall be removed from the queue and no further action on the part of the utility is required.

If Interconnection Facilities or Distribution Upgrades are required to interconnect a proposed system that passes the relevant screens, the utility shall provide the applicant with a non-binding cost estimate for the Interconnection Facilities or Distribution Upgrades within fifteen (15) Business Days of the Preliminary or Supplemental Screening Analysis. The applicant will pay the cost estimate as provided in Section D.

STEP 5: Applicant Commits to the Completion of the CESIR

Prior to commencement of the CESIR, the applicant shall provide the following information to the utility:

- a complete updated interconnection design package, if there have been any changes to the documents submitted with the application;
- proof of site control by executing the New York State Standard Site Control Certification Form, Appendix J;
- the name, phone number, and agent letter of authorization (if appropriate) of the individual(s) responsible for addressing technical and contractual questions regarding the proposed system;
- if applicable, advance payment of the costs associated with the completion of the CESIR; and
- electrical studies as requested by the utility to demonstrate that the design is within acceptable limits, inclusive and not limited to the following: system fault, relay coordination, flicker, voltage drop, and harmonics. This shall include all relay, communication, and controller set points.

The utility may require a three-line diagram for solar photovoltaic (PV) and BESS designs proposed on three-phase systems, which shall include detailed information on the wiring configuration at the PCC and an exact representation of the existing utility service.

If the utility determines that the detailed interconnection design package provided by the applicant is incomplete or otherwise deficient, the utility shall notify the applicant within ten (10) Business Days and provide a detailed explanation of the deficiencies identified and a list of what is required by the applicant. Unless otherwise notified by the utility, the CESIR review period begins upon confirmed receipt and acceptance of the applicant's interconnection design package and associated fees.

If the applicant fails to provide the utility authorization to proceed, CESIR fee, and information requested within thirty (30) Business Days of the request, the application shall be removed from the queue and no further action on the part of the utility is required.

STEP 6: Utility Completes the CESIR

The CESIR will consist of two parts:

1) a detailed review and explanation of the impacts to the utility system associated with the interconnection of the proposed system, and
2) a detailed review and explanation of the proposed system's compliance with the

applicable criteria set forth below.

A CESIR will be performed by the utility to determine if the proposed generation on the circuit results in any protective coordination, fault current, thermal, voltage, power quality, or equipment stress concerns.

The CESIR shall be completed within sixty (60) Business Days of receipt of the information set forth in Step 5. For systems utilizing type-tested equipment, the time required to complete the CESIR may be reduced. The utility shall complete the CESIR within sixty (60) Business Days, absent extraordinary circumstances, following authorization, receipt of the CESIR fee, and complete information set forth in Step 5. If the applicant fails to provide the utility authorization to proceed, CESIR fee and information requested within thirty (30) Business Days, the interconnection request shall be removed from the queue and no further action on the part of the utility is required.

If (1) the applicant requests a change that is not a Material Modification, or (2) the utility determines that additional study of the application is needed, the utility may take up to an additional forty (40) Business Days beyond the time specified above for completion of the CESIR, provided that no other application is adversely impacted.

Upon completion of the CESIR, the utility will provide the following, in writing, to the applicant:

1. notification of whether the proposed system meets the applicable criteria considered in the CESIR process;
2. utility system impacts, if any;
3. a description of where the proposed system is not in compliance with these requirements;
4. detailed description of reasoning and justification for any system upgrades and associated equipment deemed necessary for interconnection of the project;
5. a good faith, detailed estimate of the total cost of completion of the interconnection of the proposed system and/or a statement of cost responsibility for any system upgrades and associated equipment deemed necessary for interconnection of the project; and
6. a Qualifying Upgrade Disclosure, if applicable.

Appendix E sets forth the responsibility each applicant shall have with respect to the actual cost of the system upgrades and equipment necessary for the interconnection of the project. Utility cost estimates provided in the CESIR shall be detailed and broken down by specific equipment requirements, material needs, labor, overhead, and any other categories or efforts incorporated in the estimate. Contingencies associated with the cost estimates shall not exceed 15%. For Qualifying Upgrades that involve transformer banks, the utility shall identify the applicant’s share of the cost of long lead-time equipment for the purpose of installment payments, as described in Section I-D.2.

Each utility shall publish on its DG portal a cost matrix identifying the cost of the equipment typically required to interconnect DER projects, including the equipment necessary to construct system modifications. Each utility shall update its cost matrix annually, by March 31 of each year, to reflect the utility’s most recent cost experience. Cost estimates provided with a CESIR shall be based on the cost information used to develop the cost matrix in effect at the time, with adjustments or additions required for the specific project.

STEP 7: Applicant Commits to Utility Construction of Utility's System Modifications

The applicant will execute the New York Standardized Interconnection Contract for interconnection and provide the utility with an advance payment of 25% of the utility's estimated costs as identified in Step 6 within the time provided in Section I-D. The utility is not required to procure any equipment or materials associated with the project or begin construction until full payment has been received.

For applications subject to 25% and 75% payment requirements pursuant to Section I-D, the applicant shall provide both an updated three-line diagram and site-specific testing procedures within thirty (30) Business Days of making the 25% payment. For applications that do not require system modifications, a three-line diagram and site-specific testing procedure is required within thirty (30) Business Days after executing the New York State Standardized Interconnection Contract. For applications subject to a single 100% payment requirement under Section I-D, applicants are required to provide a three-line diagram and site-specific testing procedure within thirty (30) Business Days after the 100% payment. Three-line diagrams shall meet utility requirements as specified in Appendix F.

STEP 8: Project Construction

The applicant and the utility shall collaborate to identify an in-service date and develop a project construction schedule (Appendix L). The applicant shall build the facility in accordance with the utility-accepted design and the project schedule. The utility shall commence construction/installation of system modifications in accordance with the project schedule. Utility system modifications will vary in construction time depending on the extent of work and equipment required. The schedule for this work is to be discussed and agreed upon with the applicant in Step 6.

STEP 9: The Applicant's Facility is Tested in Accordance with the Standardized Interconnection Requirements

The verification testing shall be performed by the applicant in accordance with the written test procedure(s) provided by the applicant in Step 7 and any site-specific requirements identified by the utility in Step 6. The final verification testing shall be performed within ten (10) Business Days of notification to the utility by the applicant of complete installation at a mutually agreeable time, and the utility shall be given the opportunity to witness the tests. If the utility opts not to witness the tests, the applicant shall send the utility within five (5) Business Days of completion of such testing a written notification certifying that the system has been installed and tested in compliance with the SIR, the utility accepted design, and the equipment manufacturer's instructions.

STEP 10: Interconnection

The applicant's facility will be allowed to commence parallel operation upon satisfactory completion of the tests in Step 9. In addition, the applicant must have complied with and must continue to comply with the contractual and technical requirements.

STEP 11: Final Acceptance and Utility Cost Reconciliation

Except as provided in Appendix E, final project costs shall be reconciled pursuant to this section. If the utility witnessed the verification testing, then, within ten (10) Business Days of the completion of such testing, the utility will issue to the applicant either a formal letter of acceptance for interconnection or a detailed explanation of the deficiencies in the installed DG system, ESS, or Hybrid Project. If the utility did not witness the verification testing, then, within ten (10) Business Days of receiving the written test notification from Step 9, the utility will either issue to the applicant a formal letter of acceptance for interconnection, or will request that the applicant and utility set a date and time to witness operation of the installed DG system, ESS, or Hybrid Project. This witnessed verification testing must be completed within twenty (20) Business Days after being requested. Within ten (10) Business Days of the completion of any such witnessed testing, the utility will issue to the applicant either a formal letter of acceptance for interconnection or a detailed explanation of the deficiencies in the installed DG system, ESS, or Hybrid Project.

Within sixty (60) Business Days after issuance of the utility's formal letter of acceptance, or submittal of final as-built drawings to the utility, whichever occurs last, the utility shall prepare and submit to the applicant a final reconciliation statement of its actual costs less any CESIR and construction advance payments made by the applicant. The reconciliation statement shall identify any cost item that exceeded the corresponding estimate provided for that item by 115% and shall provide an explanation for the exceedance. If requested by the applicant, the utility will meet with the applicant to review the reconciliation statement. Within twenty (20) Business Days after delivery of the reconciliation statement, the applicant will receive either a bill for any balance due or a reimbursement for overpayment from the utility as determined by the utility's reconciliation. The applicant may contest the reconciliation with the utility. If the utility's final reconciliation invoice states a balance due from the applicant, unless it is challenged by a formal complaint interposed by the applicant, it shall be paid to the utility within thirty (30) Business Days or the utility reserves the right to lock the generating system offline. If the utility's final reconciliation invoice states a reimbursement for overpayment to be paid by the utility, unless the reimbursement amount is challenged by a formal complaint interposed by the applicant, it shall be paid to the applicant within thirty (30) Business Days. If the applicant is not satisfied, a formal complaint may be filed with the Secretary to the Commission.

D. Payment and Construction Milestones

1. Payment Requirements

Applicants are responsible for payment of utility system modification cost estimates in accordance with the following rules and deadlines. All project costs will be subject to the provisions of Appendix E, where applicable. In certain cases, applicants may post a standby letter of credit (SLOC) in accordance with the rules detailed in D.2 instead of making a cash payment.

When the utility's estimated cost is $10,000 or less, the applicant shall pay the utility 100% of the estimate within ninety (90) Business Days of receiving the cost estimate from the utility. Within fifteen (15) Business Days of receiving the payment, the utility will provide the applicant, via electronic communication, a signed New York State Standardized Interconnection Contract in the form of Appendix A and a written confirmation, on utility letterhead, of the compensation eligibility for which the project has qualified. The applicant will sign and return the contract to the utility within fifteen (15) Business Days. If the applicant does not return the signed contract within this period, the application shall be removed from the utility's interconnection queue, and no further action on the part of the utility is required.

When the estimated cost is greater than $10,000, the applicant will make an advance payment of 25% of the estimate to the utility within ninety (90) Business Days of receiving the cost estimate. Within fifteen (15) Business Days of receiving the applicant's payment, the utility will provide the applicant, via electronic communication, a receipt for the payment, a signed New York State Standardized Interconnection Contract in the form of Appendix A, and a written confirmation, on utility letterhead, of the compensation eligibility for which the project has qualified. The applicant will sign and return the contract to the utility within fifteen (15) Business Days. The applicant may request an extension of no more than fifteen (15) Business Days to return the contract. If the applicant does not return the signed contract within the time allowed, the application shall be removed from the utility's interconnection queue, and no further action on the part of the utility is required.

Within thirty (30) Business Days of receiving the 25% payment or SLOC, as detailed in D.2, where applicable, the utility shall provide an initial construction schedule to the applicant (consistent with Appendix L). The utility shall commence design work in accordance with its published guidance, unless otherwise directed by the applicant.

The applicant will have one hundred and twenty (120) Business Days from when the utility confirms receipt of the 25% payment or SLOC to pay the remaining 75% to the utility. The utility will provide a receipt to the applicant. Within thirty (30) Business Days of the payment, the utility will provide an updated project construction schedule (consistent with Appendix L).

If the applicant does not make a payment due under this section in the time required, the application shall be removed from the utility's interconnection queue with no further action required of the utility.

Within ten (10) Business Days of completion of design work, the utility will provide an updated upgrade cost estimate if the scope of work changed from the CESIR estimate.

If the applicant withdraws or is removed from the interconnection queue at any point after making a payment required under this section, any unspent portions of these payments will be refunded to the applicant consistent with the timelines described in Section I-C, Step 11.

If a local permitting moratorium prevents an applicant from meeting the above timelines, the utilities may grant affected project applicants an extension. To be granted an extension of the required timelines, the applicant must submit the New York State Standard Moratorium Attestation Form, Appendix I. Upon the applicant's payment of 25% of expected upgrade costs, if applicant has received its CESIR, returned the executed New York State Standardized Interconnection Contract, and submitted the Attestation Form to the utility, the due date for the remainder of the total upgrade payment shall be adjusted to one hundred and twenty (120) Business Days from the end of the moratorium. If applicable, any unused portion of the 25% payment shall be refunded if the project does not move forward after receiving an extension.

If the final acceptance as set out in Section I-C, Step 11 is not completed within twelve (12) months of the date the applicant returns the executed New York State Standardized Interconnection Contract as a result of applicant inactivity, the utility has the right to notify the applicant by U.S. first class mail with delivery receipt confirmation or via email that the applicant's project will be removed from the utility's interconnection queue if the applicant does not respond within thirty (30) Business Days of the issue of such notification and provide a project status update and/or justification as to why the project should remain in the utility's interconnection inventory for an additional period of time.

2. Standby Letters of Credit in Lieu of Cash for Certain Interconnection Upgrade Costs in Excess of $500,000

a. When an applicant's share of system modification costs, as identified in a CESIR, is estimated to exceed $500,000, applicants may provide, and utilities will accept, an irrevocable SLOC in lieu of cash in accordance with these rules. For purposes of this section, system modification costs and Qualifying Upgrade costs may not be added together to reach the $500,000 threshold. The applicant is responsible for providing the utility with a physical or electronic SLOC by the payment milestone date. If the applicant fails to provide a SLOC by the required deadline, the application shall be removed from the utility's interconnection queue, and no further action from the utility will be required. It is the applicant's responsibility to maintain the SLOC as valid for the duration of the obligation.

b. A SLOC must designate the utility as the beneficiary and be issued or guaranteed by the New York Green Bank, a U.S. or Canadian commercial bank, or a U.S. or Canadian branch of a foreign bank, with a minimum "A" rating from Standard & Poor's, Fitch, Moody's, or Dominion, as approved by the respective utility. If an issuer does not meet those requirements, the SLOC must be confirmed by another financial institution that meets the rating requirements. If an issuer no longer meets the requirements, the utility can require a replacement SLOC within fifteen (15) Business Days that meets the standards. The utility shall return the SLOC within fifteen (15) Business Days of receipt of the replacement.

c. The utility shall be entitled to charge the applicant a non-refundable administrative fee of $500. An applicant intending to post a SLOC for a payment obligation shall submit the fee with the proposed SLOC.

d. For Qualifying Upgrades, cash payments shall be due at the utility mobilization thresholds set in Appendix E (Section 2-C, "*Utility Mobilization Thresholds*"). The utility will notify the applicant at least five (5) business days in advance of any payment due date outlined in the table below.

If an applicant has posted a SLOC for a payment obligation that is non-refundable under Appendix E, failure of the applicant to make a cash payment at the time required by these rules shall be a default, and the utility shall be authorized to draw on the SLOC in the amount of the cash payment due. The utility shall return the SLOC in the circumstances when a cash deposit would be refunded under Appendix E. If an applicant that has posted a SLOC for a non-refundable payment obligation withdraws from the queue prior to the cash payment date, the utility may retain the SLOC until a replacement mechanism is provided in the form of cash and/or a SLOC from a replacement project, consistent with the requirements of Appendix E.

For Qualifying Upgrades that involve transformer banks, as defined in Appendix E, an applicant that has posted a SLOC may make its cash payments in two installments. The first installment shall be the portion of the applicant's Qualifying Upgrade Charge equal to its share of the cost of long lead-time equipment, as identified in the CESIR cost estimate. The first installment shall be due to the utility when the mobilization threshold is reached, as provided in Appendix E Section 2.C, "*Utility Mobilization Thresholds.*" Upon making the first cash installment, the applicant may choose to replace or amend the posted SLOC for the remaining balance. The utility shall return the SLOC within fifteen (15) Business Days of receipt of the replacement. The second installment, equal to the balance of the Qualifying Upgrade Charge, shall be due after the utility receives the long lead-time equipment and mobilizes to initiate construction. The utility shall provide written notice through its DG portal that the balance payment is due, and the applicant shall make the cash payment within fifteen (15) Business Days of the date of the utility's notice.

e. The following table identifies scenarios when a SLOC may be used by an applicant and the requirements for replacing a SLOC with cash.

Table 1: Scenarios for the Use of Standby Letters of Credit

Scenario #	Description	Use Cases Regarding SLOCs
1	Applicant's estimated system modification cost is at or below $500,000	N/A (SLOC not allowed) and only cash payments by the applicant to the utility at the payment due dates will be allowed
2	Applicant's estimated system modification cost exceeds $500,000 and there are either: (i) no Qualifying Upgrades; or (ii) no Qualifying Upgrades except for Line Upgrades, as defined in Appendix E	SLOC may be posted at the time the applicant's 25% payment is due; a 100% cash payment to the utility will be required, covering the full amount of the CESIR cost estimate, by the 75% payment due date.
3	Applicant's estimated system modification costs include Qualifying Upgrades (3V0, Other Substation Upgrades), as defined in Appendix E, and the applicant's Qualifying Upgrade Charge exceeds $500,000.	SLOC for the Qualifying Upgrade Charge may be posted ninety (90) Business Days following the CESIR delivery; the cash payment for the remaining balance is due when the cost-sharing mobilization threshold is reached.
4	Applicant's estimated system modifications include Transformer Banks, as defined in Appendix E, for which the applicant's Qualifying Upgrade Charge exceeds $500,000.	SLOC may be posted for the Qualifying Upgrade Charge ninety (90) Business Days following the CESIR delivery. Cash payments are required in two installments, aligned with two milestones: 1. The first payment will be a percentage of the total Qualifying Upgrade cost, based on the value of long lead-time equipment, as identified in the CESIR, when the mobilization threshold is reached. 2. The second payment will be due after the utility receives long-lead time equipment and mobilizes to initiate construction.

5	Applicant's estimated system modifications exceed $500,000 and there are both Line Upgrades and Qualifying Upgrades, as defined in Appendix E, for which the mobilization threshold has not yet been reached	SLOC may be used at the time of the applicant's 25% and 75% payment due dates to the utility with 100% of the cash payment due to the utility when the last Qualifying Upgrade achieves the mobilization threshold. The utility will not mobilize for non-shared upgrades until it receives 100% of the cash payment.

E. Application Process for Energy Storage Systems (ESS)

Except as provided in this Section, the rules in Sections I-B and I-C shall apply to applications to: construct new Hybrid Projects; construct new stand-alone storage; add an ESS to an existing DG facility; and change the operating mode of an existing Hybrid Project or stand-alone storage facility. Whether an application will be handled under Section I-B or I-C will be determined by the sum of the AC nameplate ratings of all DG facilities and ESS facilities comprising the proposed Hybrid Project.

STEP 1: The Application

An applicant proposing a Hybrid Project or stand-alone ESS shall complete and submit Appendix K with Appendix F.

The owner of an existing DG facility may apply to add an ESS by submitting a completed Appendix K to the utility at any time.

For all projects involving ESS, the utility shall review the application and respond within the time frames provided in Section I-B or I-C, as applicable.

Following interconnection of a Hybrid Project or a stand-alone ESS, the applicant may apply to the utility to change the operating characteristics of the storage component. To initiate review, the applicant shall submit a completed Appendix K specifying the proposed new operating characteristics to the utility.

STEP 2: Protection and Control Review

When performing screening analysis and system impact studies associated with ESS, operating characteristics including maximum export and import capacity shall be utilized, except that fault current contribution shall be evaluated based on aggregate AC nameplate rating. The utility's technical review shall determine whether the proposed facility, operating per the characteristics identified in the application (Appendix K), can be safely and reliably interconnected to the utility's distribution system. The applicant shall pay the costs for the utility's review in advance.

Following the completion of Step 3 in Section I.B, or upon passing the Preliminary or Supplemental Screening Analysis in Step 4 in Section I.C, based on the application and proposed operating parameters, the utility will determine if a Protection and Control Review is required. The utility will notify the applicant of this determination. The applicant will have thirty (30) Business Days from the notification to pay the nonrefundable fee for the review, which shall be calculated as $500 plus $4/kW capped at $3,000. The utilities shall have twenty (20) Business Days to perform the review and provide the results to the applicant, including a description of any modifications to the control systems that the utility determines are necessary.

Within ten (10) Business Days of an applicant's request, the utility shall discuss the results of the Protection and Control Review. Following the discussion, the applicant will have twenty (20) Business Days to determine whether or not to accept any required modifications to the control system and take the next step in the process as defined in Section I.B or I.C, as applicable, or to withdraw the application.

For all applications relating to ESS, the utility's written report of its technical review shall include a completed Attachment I, as defined below, specifying the operating parameters studied for the proposed facility. The utility and the applicant shall discuss the listed operating parameters promptly after delivery of the study results to the applicant.

For ESS applications requiring a CESIR, the utility will provide the applicant with any additional testing procedures required in connection with the ESS, using the applicant's load management control systems to limit reverse power. The utility will provide this information with the CESIR results.

STEP 3: Contract and Payment for Utility Construction Costs

An applicant proposing a Hybrid Project, stand-alone storage, or the addition of ESS to an existing DG facility shall execute the New York State Standardized Interconnection Contract for Systems including Energy Storage, and make payment to the utility for its estimated construction costs within the time required by Section D.

Each contract shall include a completed Attachment I, which shall specify the operating parameters for the interconnected ESS after consultation with the applicant.

An applicant proposing to change the operating characteristics listed in Appendix K for an existing ESS shall sign an amendment to the New York State Standard Interconnection Contract for Facilities including Energy Storage to incorporate the revised Attachment I and make payment for any utility construction costs within the time required by Section I-D.

F. Rules for Combining DG Applications

Distributed Generation applications that have been determined to be complete and that meet the following criteria may be combined:

(a) the applications must be sequential in the utility's queue on both the circuit and substation bus, or non-sequential combined applications may proceed with the lower queue position;

(b) there can be no non-SIR applications in the utility's queue between the applications that propose to aggregate;

(c) the proposed projects must be located on the same or adjacent parcels;

(d) both applications must be compensated at the same rate and; and

(e) the size of the combined projects may not exceed an AC nameplate rating of 5 MW.

If none of the applications has reached the deadline for payment of 25% of the estimated utility construction costs necessary for its interconnection, the applicant(s) may ask the utility to perform a technical review of the applications as a combined project. The applicant(s) shall submit its request in writing to the utility. The utility shall cease any ongoing work on the individual applications and notify the applicant(s) within ten (10) Business Days of any additional information that is needed to perform the requested analysis and of the fee that will be charged. The utility shall apply any unspent study fees related to the individual applications to the charge for the new study. The applicant(s) shall pay the fee and provide the information sought by the utility within ten (10) Business Days of the notification. The construction cost payment due dates for the applications that are proposed to combine will be suspended until a new due date is established pursuant to this Section.

If any of the applications proposed to be combined has made a payment for estimated utility construction costs, the applicant(s) may still submit a request to study them as a combined project as provided above. Any additional payment due dates associated with the applications shall be suspended until a new due date is established. The utility shall cease work on the individual applications and shall cancel any procurements that the applicant(s) agree should be cancelled. The applicant(s) shall bear any cost associated with such cancellations. The utility shall notify the applicant(s) of any information that is needed to perform the requested analysis and of the fee that will be charged for the study within ten (10) Business Days of receiving the request. The applicant(s) shall pay the fee and provide the information sought by the utility within ten (10) Business Days of the notification.

The utility shall have sixty (60) Business Days from receipt of the fee and the project information to perform the technical review of the combined applications. The utility's report of the results shall provide the information specified in Step 6 of Section I-C to the applicant(s). The applicant(s) may:

(1) proceed to construct the combined project;

(2) resume the interconnection of the separate applications; or

(3) withdraw one or more of the applications.

If the applicant(s) selects option (1), payment for the full amount of the estimated utility construction costs shall be due sixty (60) Business Days after receipt of the results of the technical review. If the applicant(s) selects either option (2) or (3), full payment of the construction cost associated with the applications that are to continue to interconnect shall be due within the same time period. If the applicant(s) does not meet these deadlines, the applications shall be deemed withdrawn with no further action required by the utility.

G. Interconnection On-Line Application Portal (IOAP)

Each utility shall maintain an IOAP system to provide applicants a web-based application submittal process. Hard copy, email, and/or mailed in application will no longer be allowed or accepted unless the utility IOAP systems are down for maintenance or failure. The IOAP shall also provide applicants with updated information regarding the status of their SIR application process. The system shall be customer specific and post the real-time status of the SIR process. At a minimum, the following content shall be provided:

1. The applicant's name and project/application identification number.
2. Description of the project, including at a minimum, the project's type (energy source), size, metering, and location.
3. SIR project application status, including all the steps completed and to be completed, along with corresponding completion/deadline dates associated with each step.
    - If the next action is to be taken by the utility, the expected date that action will

be completed,

- If the next action is to be taken by the applicant, what exactly is required and a contact for more information.

4. Information regarding any outstanding information request made by the utility of the applicant, and
5. The status of all amounts paid and/or due to the utility by the applicant.

Access shall be available for the customer and their authorized agent(s), such that both can access the information. The IOAP must be private and secure from unauthorized access. Access to the IOAP shall be easily found on each electric utility's Interconnection / Distributed Generation home web page.

The IOAP application process must be consistent with the latest version of the SIR and include the ability to attach associated documentation or drawings for each project. Electronic signatures shall be accepted and approved for this process.

H. Modifications

Applicants may propose a Modification at any time by submitting a request to the utility through the utility's on-line application portal and /or via email. Submission of such a request will not suspend any deadlines applicable to the pending application. The utility will review the request to determine whether the proposed Modification is a Material Modification and provide its determination to the applicant within ten (10) Business Days, unless the utility first notifies the applicant that additional information is needed to make the evaluation. In that case, the utility will have ten (10) Business Days from receipt of the additional information to determine whether the proposed Modification is a Material Modification.

A Material Modification to a project will require a new application, a new queue position, and removal of the original application if the applicant elects to move forward with the modification (if not yet interconnected).

The utility reserves the right to make the final determination as to whether a proposed change is a Material Modification.

When making the materiality determination, the utility will consider the DPS Staff posted Guidance Document on DER Material Modifications and will provide the applicant with a written explanation of its finding. At the applicant's request, the utility will meet with the applicant to discuss the materiality determination.

A Modification that is not determined to be material may still require evaluation and acceptance by the utility through the process described below. The applicant is obligated to pay any necessary study costs of the evaluation. The utility will notify the applicant of any additional funding and/or information that may be required to evaluate the Modification within five (5) Business Days of providing the materiality determination. The applicant shall have ten (10) Business Days to provide any requested information and pay the associated fees or choose to remain with the original interconnection application with associated uninterrupted timeline.

If the proposed change is not a Material Modification, and is proposed prior to the start of a CESIR, the utility will study the modified project in the CESIR process.

If the proposed change is not a Material Modification and is proposed following the start of a CESIR but no later than forty (40) Business Days after the start date, the utility may have an additional forty (40) Business Days to complete the CESIR incorporating the change.

If the proposed change is not a Material Modification and is proposed at a later date, or after completion of a CESIR, the change may require further study and will require mutual agreement between the utility and the applicant. The utility retains the right to determine the extent of evaluation necessary but will endeavor to complete any necessary study within a timeframe no longer than a standard CESIR. The applicant will be responsible for any costs related to the change.

Section II. Interconnection Requirements

A. Design Requirements

1. Common

The generator-owner shall provide appropriate protection and control equipment, including a protective device that utilizes an automatic disconnect device that will disconnect the generation in the event that the portion of the utility system that serves the generator is de-energized for any reason or for a fault in the generator-owner's system. The generator-owner's protection and control equipment shall be capable of automatically disconnecting the generation upon detection of an islanding condition and upon detection of a utility system fault.

The type and size of the generation facility or energy storage system is based on electrical generator or inverter AC nameplate rating.

The generator-owner's protection and control scheme shall be designed to ensure that the generation remains in operation when the frequency and voltage of the utility system is within the limits specified by the required operating ranges. Upon request from the utility, the generator-owner shall provide documentation detailing compliance with the requirements set forth in this document.

The specific design of the protection, control, and grounding schemes will depend on the size and characteristics of the generator-owner's generation, as well the generator-owner's load level, in addition to the characteristics of the particular portion of the utility's system where the generator-owner is interconnecting.

The generator-owner shall have, as a minimum, an automatic disconnect device(s) sized to meet all applicable local, state, and federal codes and operated by over and under voltage and over and under frequency protection. For three-phase installations, the over and under voltage function should be included for each phase and the over and under frequency protection on at least one phase. All phases of a generator or inverter interface shall disconnect for voltage or frequency trip conditions sensed by the protective devices. Voltage protection shall be wired phase to ground for single phase installations and for applications using wye grounded-wye grounded service transformers.

The settings below are listed for single-phase and three-phase applications using wye grounded- wye grounded service transformers or wye grounded-wye grounded isolation transformers. For applications using other transformer connections, a site-specific review will be performed by the utility and the revised settings identified in Step 6 of the Application Process.

The requirements set forth in this document are intended to be consistent with those contained in the most current version of IEEE Std 1547, Standard for Interconnecting Distributed Resources with Electric Power Systems. The requirements in IEEE Std 1547 above and beyond those contained in this document shall be followed and any other Standards included in or referenced to in IEEE Std 1547 shall be adhered to.

Voltage Response

The required operating range for the generators shall be as detailed in the most current version of IEEE Std 1547 and the Category (related to Area EPS abnormal conditions) as specified by the utility's technical requirements document. In addition, the generator shall not cause the system voltage at the PCC to deviate from a range of 95% to 105% of the utility system voltage. For excursions outside these limits the protective device shall automatically initiate a disconnect sequence from the utility system as detailed in the most current version of IEEE Std 1547. Clearing time is defined as the time the range is initially exceeded until the generator-owner's equipment ceases to energize the PCC and includes detection and intentional time delay. Other static or dynamic voltage functionalities shall be permitted as agreed upon by the utility and generator-owner.

Frequency Response

The required operating range for the generators shall be as detailed in the most current version of IEEE Std 1547 and the Category (related to Area EPS abnormal conditions) as specified by the utility's technical requirements document . If deemed necessary due to abnormal system conditions the utility may request that the generator operate at frequency ranges below 59.3 Hz in coordination with the load shedding schemes of the utility system. For excursions outside these limits the protective device shall automatically initiate a disconnect sequence from the utility system as detailed in the most current version of IEEE Std 1547. Clearing time is defined as the time the range is initially exceeded until the generator- owner's equipment ceases to energize the PCC and includes detection and intentional time delay. Other static or dynamic frequency functionalities shall be permitted as agreed upon by the utility and generator-owner.

Reconnection to the Utility System

If the generation facility is disconnected as a result of the operation of a protective device, the generator-owner's equipment shall remain disconnected until the utility's service voltage and frequency have recovered to acceptable voltage and frequency limits as defined in the most current version of IEEE Std 1547 for a minimum of five (5) minutes. Systems greater than 25 kW that do not utilize inverter based interface equipment shall not have automatic recloser capability unless otherwise approved by the utility. If the utility determines that a facility must receive permission to reconnect, then any automatic reclosing functions must be disabled and verified to be disabled during verification testing.

2. Synchronous Generators

Synchronous generation shall require synchronizing facilities. These shall include automatic synchronizing equipment or manual synchronizing with relay supervision, voltage regulator, and power factor control.

For all synchronous generators sufficient reactive power capability shall be provided by the generator-owner to withstand normal voltage changes on the utility's system. The generator voltage VAR schedule, voltage regulator, and transformer ratio settings shall be jointly determined by the utility and the generator-owner to ensure proper coordination of voltages and regulator action. Generator-owners shall have synchronous generator reactive power capability to withstand voltage changes up to 5% of the base voltage levels.

A voltage regulator must be provided and be capable of maintaining the generator voltage under steady state conditions within plus or minus 1.5% of any set point and within an operating range of plus or minus 5% of the rated voltage of the generator.

Generator-owners shall adopt one of the following grounding methods for synchronous generators interconnected to effectively grounded circuits:

a. Solid grounding
b. High- or low-resistance grounding
c. High- or low-reactance grounding
d. Ground fault neutralizer grounding

Synchronous generators shall not be permitted to connect to utility secondary network systems without the acceptance of the utility.

3. Induction Generators

Induction generation may be connected and brought up to synchronous speed (as an induction motor) if it can be demonstrated that the initial voltage drop measured at the PCC is acceptable based on current inrush limits. The same requirements also apply to induction generation connected at or near synchronous speed because a voltage dip is present due to an inrush of magnetizing current. The generator-owner shall submit the expected number of starts per specific time period and maximum starting kVA draw data to the utility.

Starting or rapid load fluctuations on induction generators can adversely impact the utility's system voltage. Corrective step-switched capacitors or other techniques may be necessary. These measures can, in turn, cause ferro resonance. If these measures are installed on the customer's side of the PCC, the utility will review these measures and may require the customer to install additional equipment.

4. Inverters

Direct current generation can only be installed in parallel with the utility's system using a synchronous inverter. The design shall be such as to disconnect this synchronous inverter upon a utility system event. Inverters intended to provide local grid support during system events that result in voltage and/or frequency excursions as described in Section II.A.1 shall be provided with the required onboard functionality to allow for the equipment to remain online for the duration of the event.

It is recommended that equipment be selected from the Department of Public Service "Certified Interconnection Equipment list" maintained on the Commission's website. Interconnected DG systems utilizing equipment not found in such list must meet all functional requirements of the current version of IEEE Std 1547 and be protected by utility grade relays (as defined in these requirements) using settings approved by the utility and verified in the field. The field verification test must demonstrate that the equipment meets the voltage and frequency requirements detailed in this section.

Synchronization or re-synchronization of an inverter to the utility system shall not result in a voltage deviation that exceeds the requirements contained in Section II.E, Power Quality. Only inverters designed to operate in parallel with the utility system shall be utilized for that purpose.

5. Minimum Protective Function Requirements

Protective system requirements for distributed generation facilities result from an assessment of many factors, including but not limited to:

- Type and size of the distributed generation facility
- Voltage level of the interconnection
- Location of the distributed generation facility on the circuit
- Distribution transformer
- Distribution system configuration
- Available fault current
- Load that can remain connected to the distributed generation facility under isolated conditions
- Amount of existing distributed generation on the local distribution system.

As a result, protection requirements cannot be standardized according to any single criteria. Minimum protective function requirements shall be as detailed in the table below. Function numbers, as detailed in the latest version of ANSI C37.2, are listed with each function. All voltage, frequency, and clearing time set points shall be field adjustable.

Synchronous Generators	**Induction Generators**	**Inverters**
Over/Under Voltage (Function 27/59)	Over/Under Voltage (Function 27/59)	Over/Under Voltage (Function 27/59)
Over/Under Frequency (Function 81O/81U)	Over/Under Frequency (Function 81O/81U)	Over/Under Frequency (Function 81O/81U)
Anti-Islanding Protection	Anti-Islanding Protection	Anti-Islanding Protection
Overcurrent (Function 50P/50G/51P/51G)	Overcurrent (Function 50P/50G/51P/51G)	Overcurrent (Function 50P/50G/51P/51G)

For energy storage systems or distributed generation where net export is limited, Reverse Power (Function 32) shall be required.

The need for additional protective functions shall be determined by the utility on a case-by-case basis. If the utility determines a need for additional functions, it shall notify the generator-owner in writing of the requirements. The notice shall include a description of the specific aspects of the utility system that necessitate the addition, and an explicit justification for the necessity of the enhanced capability. The utility shall specify and provide settings for those functions that the utility designates as being required to satisfy protection practices. Any protective equipment or setting specified by the utility shall not be changed or modified at any time by the generator- owner without written consent from the utility.

The generator-owner shall be responsible for ongoing compliance with all applicable local, state, and federal codes and standardized interconnection requirements as they pertain to the interconnection of the generating equipment. Protective devices shall utilize their own current transformers and potential transformers and not share electrical equipment associated with utility revenue metering.

A failure of the generator-owner's protective devices, including loss of control power, shall open the automatic disconnect device, thus disconnecting the generation from the utility system. A generator-owner's protection equipment shall utilize a non-volatile memory design such that a loss of internal or external control power, including batteries, will not cause a loss of interconnection protection functions or loss of protection set points.

All interface protection and control equipment shall operate as specified independent of the calendar date.

For monitoring and control of new DG projects, the most current version of the Monitoring and Control Criteria shall be employed by the utilities to evaluate the need for such equipment. The Monitoring and Control Criteria document was developed and agreed to through a collaborative process as part of the Interconnection Technical Working Group (ITWG). This document can be found on the Department of Public Service website (www.dps.ny.gov) at the Distributed Generation/Interconnections tab under Interconnection Technical Working Group Information. The communications hardware, protocols, and data models must comply with utility standards.

6. Metering

Metering requirements shall be determined by the configuration of the DER system. New metering or modifications to existing metering will be reviewed on a case-by-case basis and shall be consistent with metering requirements adopted by the Commission.

Any incremental metering costs are included in interconnection costs that may be required of an applicant.

The following table summarizes the applicable New York Net Metering Rules:

New York (PSL §66-l) - Net Metering*			
Incentive Type:	Net Metering Rules		
Eligible Renewable/Other Technologies:	Wind		
Applicable Sectors:	Residential	Non-Residential	Farm-Service Wind
Limit on System Size:	25 kW	Up to 2 MW	500 kW
Remote Net Metering	No**	Yes	Yes
Limit on Overall Enrollment:	.3% of 2005 Demand per IOU		

* Refer to specific utility tariff leaves for more detailed rules and regulations applicable to net metering wind electric generating systems.

** Residential customers who own or operate a farm operation as defined by Agriculture and Markets Law §301(11) and locate solar photovoltaic, micro-hydroelectric, wind, or fuel cells on property owned or leased by the customer are also eligible for remote net metering.

B. Operating Requirements

The generator-owner shall provide a 24-hour telephone and email/electronic contact. This contact will be used by the utility to arrange access for repairs, inspection, or emergencies. The utility will make such arrangements (except for emergencies) during normal business hours. For all required disconnections of the generator-owner's system to facilitate non-emergency utility work on the electric power system, the utility will provide two (2) Business Days' advance notice to the generator-owner contact with an indication of anticipated duration.

Voltage and frequency trip set point adjustments shall be accessible to service personnel only. Any changes to these settings must be reviewed and approved by the utility.

The generator-owner shall not supply power to the utility during any outages of the utility system that serves the PCC. The generator-owner's generation may be operated during such outages only with an open tie to the utility. Islanding will not be permitted. The generator-owner shall not energize a de-energized utility circuit for any reason.

Energy storage systems cannot disconnect to self-generate if their operating characteristics require their stored energy to be discharged at that time. All control systems must be password protected from modification by the interconnection customer and property owner following Interconnection.

The disconnect switch specified for system size larger than 25 kW and non-inverter based systems of 25 kW or less in Section II.D, Disconnect Switch, may be opened by the utility at any time for any of the following reasons:

a. to eliminate conditions that constitute a potential hazard to utility personnel or the general public;
b. pre-emergency or emergency conditions on the utility system;
c. a hazardous condition is revealed by a utility inspection; protective device tampering; or,
d. parallel operation prior to utility approval to interconnect.

The disconnect switch may be opened by the utility for the following reasons, after notice to the responsible party has been delivered and a reasonable time to correct (consistent with the conditions) has elapsed:

a. A generator-owner has failed to make available records of verification tests and maintenance of its protective devices;
b. A generator-owner's system adversely impacts the operation of utility equipment or equipment belonging to other utility customers; or,
c. A generator-owner’s system is found to adversely affect the quality of service to adjoining customers.

The utility will provide a name and telephone number so that the generator-owner can obtain information about the utility lock-out.

The generator-owner shall be allowed to disconnect from the utility without prior notice to self-generate.

If a generator-owner proposes any modification to the system that has an impact on the interface at the PCC after it has been installed and a contract between the utility and the generator-owner has already been executed, then any such modifications must be reviewed and approved by the utility before the modifications are made.

C. Dedicated Transformer

The utility reserves the right to require a power-producing facility to connect to the utility system through a dedicated transformer. The transformer shall either be provided by the connecting utility at the generator-owner’s expense, purchased from the utility, or conform to the connecting utility’s specifications. The transformer that is part of the normal electrical service connection of a generator-owner’s facility may meet this requirement if there are no other customers supplied from it. A dedicated transformer is not required if the installation is designed and coordinated with the utility to protect the utility system and its customers adequately from potential detrimental net effects caused by the operation of the generator.

If the utility determines a need for a dedicated transformer, it shall notify the generator-owner in writing of the requirements. The notice shall include a description of the specific aspects of the utility system that necessitate the addition, the conditions under which the dedicated transformer is expected to enhance safety or prevent detrimental effects, and the expected response of a normal, shared transformer installation to such conditions.

D. Disconnect Switch

Generating equipment with system size larger than 25 kW and non-inverter based systems of 25 kW or less shall be capable of being isolated from the utility system by means of an external, manual, visible, gang-operated, load break disconnecting switch. The disconnect switch shall be installed, owned, and maintained by the customer-generator, and located between the generating equipment and its interconnection point with the utility system.

The disconnect switch must be rated for the voltage and current requirements of the installation.

The basic insulation level (BIL) of the disconnect switch shall be such that it will coordinate with that of the utility's equipment. Disconnect devices shall meet applicable requirements of the most current revision of UL, ANSI, and IEEE standards, and shall be installed to meet all applicable local, state, and federal codes. (New York City Building Code may require additional certification.)

The disconnect switch shall be clearly marked, "Generator Disconnect Switch," with permanent 3/8 inch or larger letters.

The customer-generator will propose, and the utility will approve, the location of the disconnect switch. The location and nature of the disconnect switch shall be indicated in the immediate proximity of the electric service entrance. The disconnect switch shall be readily accessible for operation and locking by utility personnel in accordance with Section II.B, Operating Requirements. The disconnect switch must be lockable in the open position with a 3/8" shank utility padlock.

For installations above 600V or with a full load output of greater than 960A, a draw-out type circuit breaker with the provision for padlocking at the draw-out position will not be an acceptable disconnect switch for the purposes of this requirement unless the use of such a circuit breaker is specifically granted by the utility, based on site-specific technical requirements. If the utility grants such use, the generator-owner will be required, upon the utility's request, to provide qualified operating personnel to open the draw-out circuit breaker and ensure isolation of the DG system, with such operation to be witnessed by the utility followed immediately by the utility locking the device to prevent re-energization. In an emergency or outage situation, where there is no access to the draw- out breaker or no qualified personnel, utilities may disconnect the electric service to the premise in order to isolate the DG system.

E. Power Quality

The requirements for acceptable flicker levels shall be in accordance with the latest version of IEEE Std 1453 Recommended Practice for the Analysis of Fluctuating Installations on Power Systems. Short and long-term perception of flicker shall be within the planning and compatibility levels delineated in this standard. Mitigation measures necessary to comply with these requirements shall at the generator-owner's expense.

F. Power Factor

If the average power factor, as measured at the PCC, is less than 0.9 (leading or lagging), the method of power factor correction necessitated by the installation of the generator will be negotiated with the utility as a commercial item. If the average power factor of the generator is proven to be above the minimum of 0.9 (leading or lagging) by the customer and accepted by the utility, that power factor value shall be used for any further utility design calculations and requirements.

Induction power generators may be provided VAR capacity from the utility system at the generator-owner's expense. The installation of VAR correction equipment by the generator-owner on the generator-owner's side of the PCC must be reviewed and approved by the utility prior to installation.

G. Islanding

Systems must be designed and operated so that islanding is not sustained on utility distribution circuits or on substation bus and transmission systems. The requirements listed in this document are designed and intended to prevent islanding. Special protection schemes and system modifications may be necessary based on the capacity of the proposed system and the configuration and existing loading on the subject circuit.

For inverter based systems, evaluation of the need for special measures to prevent unintentional islanding on radial distribution systems should be based on best practices related to the most current version of the Unintentional Islanding Protection Practice Connected to the Distribution System. This document can be found on the Department of Public Service website (www.dps.ny.gov) at the Distributed Generation/Interconnections tab under Interconnection Technical Working Group Information.

The need for zero sequence voltage (3V0) and direct transfer trip (DTT) protection schemes shall be evaluated based on minimum loads on the associated feeder and substation bus, including certain fault conditions resulting from system installation to protect for an islanded condition.

H. Equipment Certification

In order for the equipment to be acceptable for interconnection to the utility system without additional protective devices, the interface equipment must be equipped with the minimum protective function requirements listed in the table in Section II.A.5 and be tested by a Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration (OSHA) in compliance with the most current revision of UL 1741, including supplement B (UL 1741 SB), with settings as specified in the utility's technical requirements document.

For each interconnection application, documentation including the proposed equipment certification, stating compliance with the most recent version of UL 1741, including UL 1741 SB, with settings as specified in the utility's technical requirements document, by an NRTL, shall be provided by the applicant to the utility. Supporting information from an NRTL website or UL's website stating compliance is acceptable for documentation.

If an equipment manufacturer, vendor, or any other party desires, documentation indicating compliance as stated above may be submitted to the Department of Public Service for listing under the certified equipment list on the Department of Public Service website (www.dps.ny.gov) at the Distributed Generation/Interconnections tab.

Certification information for equipment tested and certified to the most current revision of UL 1741, including UL 1741 SB, with settings as specified in the utility's technical requirements document, by a non-NRTL shall be provided by the manufacturer, or vendor, to the contacts listed on the Department of Public Service website for review before final acceptance and posting under the certified equipment list. Utilities are not responsible for reviewing and approving equipment tested and certified by a non-NRTL.

If a NRTL certifies equipment to the most current version of UL 1741, including UL 1741 SB, with settings as specified in the utility's technical requirements document, and compliance documentation is submitted to the utility, the utility shall accept such equipment for interconnection in New York State. All equipment certified to the most current revision of UL 1741, including UL 1741 SB, with settings as specified in the utility's technical requirements document, by an NRTL shall be deemed 'certified equipment' even if it does not appear on the Commission's website under the Certified Equipment list.

Utility grade relays need not be certified per the requirements of this section.

For DG systems that are already interconnected with the utility's electrical system and seek to use the New York State Standardized Interconnection Requirements and Application Process in order to qualify for net metering, no DG system will be required to obtain recertification the latest equipment certification standards, as long as the DG system met the equipment certification requirements by the utility in effect at the time of the DG unit's interconnection.

I. Verification Testing

All interface equipment must include a verification test procedure as part of the documentation presented to the utility in the course of the interconnection process. Except for the case of small single-phase inverters as discussed later, the verification test must establish that the protection settings meet the SIR requirements. The verification testing may be site-specific and is performed periodically to assure continued acceptable performance.

Upon initial parallel operation of a generating system, or any time interface hardware or software is changed, the verification test must be performed. A qualified individual must perform verification testing in accordance with the manufacturer's published test procedure. Qualified individuals include professional engineers, factory-trained and certified technicians, and licensed electricians with experience in testing protective equipment. The utility reserves the right to witness verification testing or require written certification that the testing was successfully performed.

Verification testing shall be performed at least once every four years. All verification tests prescribed by the manufacturer shall be performed. If wires must be removed to perform certain tests, each wire and each terminal must be clearly and permanently marked. The generator-owner shall maintain verification test reports for inspection by the utility.

Single-phase inverters and inverter systems rated 25 kW and below shall be verified upon initial parallel operation and once every four years as follows: the generator-owner shall interrupt the utility source and verify that the equipment automatically disconnects and does not reconnect for at least five minutes after the utility source is reconnected. The owner shall maintain a log of these operations for inspection by the connecting utility. Any system that depends upon a battery for trip power shall be checked and logged at least annually for proper voltage. Once every four (4) years the battery must be either replaced or a discharge test performed.

J. Interconnection Inventory

The utilities will manage the queue of interconnection applications in their inventories in the order in which they are received and according to the timelines set forth in this document.

To ensure applications are addressed in a timely manner and monitor the overall interconnection activities, utilities shall submit an SIR inventory of projects monthly to the Public Service Commission by the 15th day of the following month. Therefore, 12 interconnection inventory submissions shall be provided each year by each of the electric utilities. Utilities shall provide DPS Staff with redacted and unredacted versions of its interconnection inventory, including the current queue, for the associated time period in Excel format. At a minimum, the following information shall be provided in the inventory:

1. Utility Name
2. Applicant Name
3. Developer
4. Application No.
5. Circuit ID
6. Substation
7. System Type
8. System Capacity
9. Metering Configuration
10. Protective Equipment
11. Application Review Start and End date
12. Preliminary Screening Analysis Start and End date
13. CESIR Start and End date
14. CESIR Costs
15. Utility CESIR Costs
16. Customer CESIR Costs
17. Utility System Upgrade Costs
18. Customer System Upgrade Costs
19. Verification Testing date
20. Final Letter of Acceptance date

Section III. Glossary of Terms

Automatic Disconnect Device: An electronic or mechanical switch used to isolate a circuit or piece of equipment from a source of power without the need for human intervention.

Battery Energy Storage System (BESS): A commercially-available mechanical, electrical, or electro-chemical means to store and release electrical energy, using battery chemistries for grid-scale applications (*e.g.*, lithium-ion), and its associated electrical inversion device and control functions that may stand-alone or be paired with a distributed generator at a point of common coupling. BESS's shall comply with all ESS rules and requirements, unless otherwise specifically excepted.

Business Day: Monday through Friday, excluding utility holidays.

Cease to Energize: Cessation of energy flow capability.

Coordinated Electric System Interconnection Review (CESIR): Any studies performed by utilities to ensure that the safety and reliability of the electric grid with respect to the interconnection of distributed generation as discussed in this document.

Dedicated Transformer: A transformer installed by the utility to isolate a DG system.

Developer: The applicant or the contractor identified in Appendix F as the agent for the customer. A single developer includes all legal entities associated or affiliated with a given company ("Affiliates") where Affiliates means any person controlling, controlled by, or under common control with, any other person; where "control" shall mean the ownership of, with right to vote, 50 percent or more of the outstanding voting securities, equity, membership interests, or equivalent, of such person.

Direct Transfer Trip: Remote operation of a circuit breaker by means of a communication channel.

Disconnect (verb): To isolate a circuit or equipment from a source of power. If isolation is accomplished with a solid-state device, "Disconnect" shall mean to cease the transfer of power.

Disconnect Switch: A mechanical device used for isolating a circuit or equipment from a source of power.

Distributed Energy Resources (DER): Energy sources that consist of distributed generation facilities or energy storage systems or any combination thereof.

Distributed Generation (DG): Generation facilities supplementing on-site load or non-centralized electric power production facilities interconnected at the distribution side of an electric power system.

Draw-out Type Circuit Breaker: Circuit breakers that are disconnected by physically separating, or racking, the breaker assembly away from the switchgear bus.

Electric Power System (EPS): Refers to the electric power system owned, controlled, and/or operated by the utility and used to provide transmission and/or distribution services to its customers.

Energy Storage System (ESS): A commercially-available mechanical, electrical or electro-chemical means to store and release electrical energy, and its associated electrical inversion device and control functions that may stand-alone or be paired with a distributed generator at a point of common coupling.

Generator-Owner: An applicant to operate on-site power generation equipment in parallel with the utility grid per the requirements of this document.

Hosting Capacity: The amount of distributed energy that can be interconnected without requiring electric infrastructure upgrades or adversely affecting power quality or reliability under current configurations.

Hybrid Project: A facility that operates, or is planned to operate, as a distributed generator paired with an energy storage system at a point of common coupling.

Islanding: A condition in which a portion of the utility system that contains both load and distributed generation is isolated from the remainder of the utility system (Adopted from IEEE Std 929.).

Material Modification: A Modification to a facility that may have adverse impacts on subsequently queued applications in the interconnection queue, or any Modification described below (regardless of impact to a queued project):

1. A change in the physical location of the DER such that the Property Owner Consent Form or Site Control Certification Form as required by the SIR is no longer valid.
2. A change in the PCC to a location on a different line segment or different distribution feeder for projects interconnecting to the utility's radial system, or any change in PCC for projects interconnecting to the utility's network system.
3. An increase in the nameplate kVA or kW rating of the originally proposed distributed generation facility or energy storage system of more than 2%.
4. An additional distributed generation or energy storage system (other than the 2% increase in nameplate in item 3 above) not disclosed in the original application, where a separate and distinct distributed generation facility or energy storage system already exists behind the same proposed PCC. This would include existing non-disclosed distributed generation or energy storage systems or a request for additional distributed generation or energy storage systems at the project site.

Maximum Export: The maximum export capacity of an Energy Storage System to the distribution grid at the PCC communicated by the Applicant and studied as such by the utility per their review of the impacts on the utility system based on the operating characteristic of the Energy Storage System.

Maximum Import: The maximum import capacity of an Energy Storage System from the distribution grid at the PCC communicated by the Applicant and studied as such by the utility per their review of the impacts on the utility system based on the operating characteristic of the Energy Storage System.

Mobilization Threshold: The minimum percentage of a Qualifying Upgrade cost that must be funded by Participating Projects to trigger the utility to begin the construction process for the Qualifying Upgrade.

Modification: A change to the ownership, equipment, equipment ratings, equipment configuration, or operating characteristics* of the facility, or to schedules* associated with the facility as described in the application.
*Modifications that alter operating characteristics or schedules may be deemed material. Please consult with host utility for review and resolution.

Multi-Value Distribution (MVD): A transformer bank installation or replacement identified by the utility in its Capital Investment Plan as a Multi-Value Distribution project.

Network: A network (also known as an area network) is comprised of multiple, primary feeders supplying network transformers tied together in parallel on the secondary side to provide energy into a low voltage grid.

Participating Project: A Triggering Project or a Sharing Project that benefits from and shares costs of a Qualifying Upgrade. A Participating Project must be greater than 50 kW AC nameplate rating in size. Where Participating Projects are projects all proposed by the same developer, within a six-month period, such projects must be greater than 50 kW AC nameplate rating in aggregate.

Point of Common Coupling (PCC): The point at which the interconnection between the electric utility and the customer interface occurs. Typically, this is the customer side of the utility revenue meter.

Preliminary Review: A review of the generator-owner's proposed system capacity, location on the utility system, system characteristics, and general system regulation to determine if the interconnection is viable.

Proactive 3V0: A utility-initiated upgrade where the utility installs 3V0 prior to any applicant payment and collects pro rata payments from interconnecting projects that utilize the upgrade.

Protective Device: A device that continuously monitors a designated parameter related to the operation of the generation system that operates if preset limits are exceeded.

Qualifying Upgrade: System modifications which result in an increase to the Hosting Capacity of the utility's distribution system beyond that required to interconnect a Triggering Project that can be shared by multiple Distributed Generation/Energy Storage System projects and whose costs are greater than $250,000.

Qualifying Upgrade Disclosure: An exhibit to the CESIR presenting the use case and specifics of a Qualifying Upgrade, including the technology option(s) considered to address the electric system impacts and total estimated Qualifying Upgrade cost and increase in Hosting Capacity as well as the resulting capacity increase in shared cost expressed in kW.

Required Operating Range: The range of magnitudes of the utility system voltage or frequency where the generator-owner's equipment, if operating, is required to remain in operation for the purposes of compliance with UL 1741. Excursions outside these ranges must result in the automatic disconnection of the generation within the prescribed time limits.

Safety Equipment: Includes dedicated transformers or equipment and facilities to protect the safety and adequacy of electric service provided to other customers.

Sharing Project: A project that benefits from and contributes to the cost of a Qualifying Upgrade holding an interconnection queue position after the Triggering Project.

Spot Network: A spot network is a network within a smaller area network where one or more multiple transformers are dedicated to serve a single customer or large energy-consuming facility such as a high-rise building.

Stand-Alone Storage: An energy storage system that is solely connected to a point of common coupling and not paired with a distributed generator.

Triggering Project: The application in the queue at a given substation or feeder whose proposed interconnection triggers the need for a Qualifying Upgrade.

Utility Grade Relay: A relay that is constructed to comply with, as a minimum, the most current version of the following standards for non-nuclear facilities:

Standard	Conditions Covered
ANSI/IEEE C37.90	Usual Service Condition Ratings - ● Current and Voltage Maximum design for all relay AC and DC auxiliary relays ● Make and carry ratings for tripping contacts Tripping contacts duty cycle ● Dielectric tests by manufacturer ● Dielectric tests by user
ANSI/IEEE C37.90.1	Surge Withstand Capability (SWC) Fast Transient
Test IEEE C37.90.2	Radio Frequency Interference
ANSI C37.2	Electric Power System Device Function
Numbers IEC 255-21-1	Vibration
IEC 255-22-2	Electrostatic Discharge
IEC 255-5	Insulation (Impulse Voltage Withstand)

Verification Test: A test performed upon initial installation and repeated periodically to determine that there is continued acceptable performance.

Wind, Net Meter, Residential Applicant: A residential applicant who is proposing to install a wind electric generating system, not to exceed a combined rated capacity of 25 kW, located and used at the applicant's primary residence, per the requirements of New York State Public Service Law §66-1.

Wind, Net Meter, Non-Residential Applicant: A non-residential applicant who is proposing to install a wind electric generating system located and used at the applicant's premises, not to exceed 2 MW, pursuant to New York State Public Service Law §66-1.

Wind, Net Meter, Farm Applicant: A farm applicant who is proposing to install a wind electric generating system, not to exceed a combined rated capacity of 500 kW, located and used at the applicant's primary residence, per the requirements of New York State Public Service Law §66-l.

APPENDIX A

NEW YORK STATE STANDARDIZED CONTRACT FOR INTERCONNECTION OF NEW DISTRIBUTED GENERATION UNITS AND/OR ENERGY STORAGE SYSTEMS WITH CAPACITY OF 5 MW OR LESS CONNECTED IN PARALLEL WITH UTILITY DISTRIBUTION SYSTEMS

Interconnection Customer Information:	**Utility Information:**
Name:	Name:
Address:	Address:
Telephone:	Telephone:
Fax:	Fax:
Email:	Email:
Unit Application/File No.:	Utility Account Number:

DEFINITIONS

Delivery Service means the services the Utility may provide to deliver capacity or energy generated by the Interconnection Customer to a buyer to a delivery point(s), including related ancillary services.

Energy Storage System (ESS) means a commercially available mechanical, electrical, or electro-chemical means to store and release electrical energy, and its associated electrical inversion device and control functions that may be stand-alone or paired with a distributed generator at a point of common coupling.

Interconnection Customer means the owner of the Unit.

Interconnection Facilities means the equipment and facilities on the Utility's system necessary to permit operation of the Unit in parallel with the Utility's system.

Material Modification means a Modification to a Unit that may have adverse impacts on the Utility's system, Utility customers, other projects, or applications in the interconnection queue.

Modification means a change to the ownership, equipment, equipment ratings, equipment configuration, or operating conditions of the Unit.

Premises means the real property where the Unit is located.

SIR means the New York State Standardized Interconnection Requirements for new distributed generation units and/or energy storage systems with a nameplate capacity of 5 MW or less connected in parallel with the Utility's distribution system.

Unit means the distributed generation, stand-alone ESS, or combined generation and ESS facilities approved by the Utility for operation in parallel with the Utility's system. This Agreement relates only to such Unit, but a new agreement shall not be required if the Interconnection Customer makes physical alterations to the Unit that do not result in an increase in its nameplate generating capacity. The nameplate generating capacity or inverter/converter rating of the Unit shall not exceed 5 MW.

Utility means [insert legal name of the interconnecting utility].

I. TERM AND TERMINATION

1.1 Term: This Agreement shall become effective when executed by both Parties and shall continue in effect until terminated.

1.2 Termination: This Agreement may be terminated as follows:

a. The Interconnection Customer may terminate this Agreement at any time, by giving the Utility sixty (60) days' written notice.

b. Failure by the Interconnection Customer to seek final acceptance by the Utility within twelve (12) months after completion of the utility construction process described in the SIR shall automatically terminate this Agreement.

c. Either Party may, by giving the other Party at least sixty (60) days' prior written notice, terminate this Agreement in the event that the other Party is in default of any of the material terms and conditions of this Agreement. The terminating Party shall specify in the notice the basis for the termination and shall provide a reasonable opportunity to cure the default.

d. The Utility may, by giving the Interconnection Customer at least sixty (60) days' prior written notice, terminate this Agreement for cause. The Interconnection Customer's non-compliance with an upgrade to the SIR, unless the Interconnection Customer's installation is "grandfathered," shall constitute good cause.

1.3 Disconnection and Survival of Obligations: Upon termination of this Agreement the Unit will be disconnected from the Utility's electric system. The termination of this Agreement shall not relieve either Party of its liabilities and obligations, owed or continuing at the time of the termination.

1.4 Suspension: This Agreement will be suspended during any period in which the Interconnection Customer is not eligible for Delivery Service from the Utility

II. SCOPE OF AGREEMENT

2.1 Scope of Agreement: This Agreement relates solely to the conditions under which the Utility and the Interconnection Customer agree that the Unit may be interconnected to and operated in parallel with the Utility’s system.

2.2 Electricity Not Covered: The Utility shall have no duty under this Agreement to account for, pay for, deliver, or return in kind any electricity produced by the Facility and delivered into the Utility’s System unless the system is net metered as described in Public Service Law Section 66-l.

III. INSTALLATION, OPERATION AND MAINTENANCE OF UNIT

3.1 Compliance with SIR: Subject to the provisions of this Agreement, the Utility shall be required to interconnect the Unit to the Utility's system, for purposes of parallel operation, if the Utility accepts the Unit as in compliance with the SIR. The Interconnection Customer shall have a continuing obligation to maintain and operate the Unit in compliance with the SIR.

3.2 Observation of the Unit - Construction Phase: The Utility may, in its discretion and upon reasonable notice, perform reasonable on-site verifications during the construction of the Unit. Whenever the Utility chooses to exercise its right to perform observations herein it shall specify to the Interconnection Customer its reasons for its decision to perform the observation. For purposes of this paragraph and paragraphs 3.3 through 3.5, the term "on-site verification" shall not include testing of the Unit, and verification tests shall not be required except as provided in paragraphs 3.3 and 3.4.

3.3 Observation of the Unit - Ten-day Period: The Utility may perform on-site verifications of the Unit and observe the execution of verification testing within a reasonable period of time, not exceeding ten (10) business days after system installation. The Unit will be allowed to commence parallel operation upon satisfactory completion of the verification test. The Interconnection Customer must have complied with and must continue to comply with all contractual and technical requirements.

3.4 Observation of the Unit - Post-Ten-day Period: If the Utility does not perform an on-site verification of the Unit and observe the execution of verification testing within the ten-day period, the Interconnection Customer will send the Utility within five (5) days of the verification testing a written notification certifying that the Unit has been installed and tested in compliance with the SIR, the utility-accepted design and the equipment manufacturer's instructions. The Interconnection Customer may begin to produce energy upon satisfactory completion of the verification test. After receiving the verification test notification, the Utility will either issue to the Interconnection Customer a formal letter of acceptance for interconnection, or may request that the applicant and utility set a date and time to perform an on-site verification of the Unit and make reasonable inquiries of the Interconnection Customer, but only for purposes of determining whether the verification tests were properly performed. The Interconnection Customer shall not be required to perform the verification tests a second time, unless irregularities appear in the verification test report or there are other objective indications that the tests were not properly performed in the first instance.

3.5 Observation of the Unit - Operations: The Utility may perform on-site verification of the operations of the Unit after it commences operations if the Utility has a reasonable basis for doing so based on its responsibility to provide continuous and reliable utility service or as authorized by the provisions of the Utility's Retail Electric Tariff relating to the verification of Interconnection Customer installations generally.

3.6 Costs of Interconnection Facilities: During the term of this Agreement, the Utility shall design, construct and install the Interconnection Facilities. The Interconnection Customer shall be responsible for paying the incremental capital cost of such Interconnection Facilities attributable to the Interconnection Customer's Unit. All costs associated with the operation and maintenance of the Dedicated Facilities after the Unit first produces energy shall be the responsibility of the Utility.

3.7 Modifications to the Unit: The Interconnection Customer may request a Modification at any time after commencement of parallel operation. The Utility shall evaluate the request and determine whether the proposed change is a Material Modification in accordance with the rules for requesting changes to applications in the SIR. A Material Modification will be studied pursuant to the procedures in the SIR for new applications. In the case of a non-material modification that is accepted by the Utility, the parties will execute an amendment to this Agreement describing the Unit changes that have been approved.

IV. DISCONNECTION OF THE UNIT

4.1 Emergency Disconnection: The Utility may disconnect the Unit, without prior notice to the Interconnection Customer (a) to eliminate conditions that constitute a potential hazard to Utility personnel or the general public; (b) if pre-emergency or emergency conditions exist on the Utility system; (c) if a hazardous condition relating to the Unit is observed by a Utility inspection; or (d) if the Interconnection Customer has tampered with any protective device. The Utility shall notify the Interconnection Customer of the emergency if circumstances permit. The Interconnection Customer shall notify the Utility promptly when it becomes aware of an emergency condition that affects the Unit that may reasonably be expected to affect the Utility EPS.

4.2 Non-Emergency Disconnection Due to Unit Performance: The Utility may disconnect the Unit, after notice to the responsible party has been provided and a reasonable time to correct, consistent with the conditions, has elapsed, if (a) the Interconnection Customer has failed to make available records of verification tests and maintenance of his protective devices; (b) the Unit system interferes with Utility equipment or equipment belonging to other customers of the Utility; (c) the Unit adversely affects the quality of service of adjoining customers; (d) the ESS does not operate in compliance with the operating parameters and limits described in Attachment 1 to this Agreement.

4.3 Non-Emergency Disconnection for Utility Work: The Utility may disconnect the Unit after notice to Interconnection Customer when necessary for routine maintenance, construction, and repairs on the Utility EPS. The Interconnection Customer may request to reconnect its service prior to the completion of the Utility's work. The Utility shall accommodate such requests, provided that the Interconnection Customer shall be responsible for the costs of the Utility's review and any system modifications required to reconnect the Unit ahead of schedule.

4.4 Disconnection by Interconnection Customer: The Interconnection Customer may disconnect a Unit with an AC nameplate rating above 300 kW upon 18 hours advance notice to the Utility if the planned shutdown will last 8 hours or more. For non-emergency forced outages lasting 8 hours or more, the Interconnection Customer shall notify the Utility within 24 hours of the commencement of the shutdown.

4.5 Utility Obligation to Cure Adverse Effect: If, after the Interconnection Customer meets all interconnection requirements, the operations of the Utility are adversely affecting the performance of the Unit or the Customer's premises, the Utility shall immediately take appropriate action to eliminate the adverse effect. If the Utility determines that it needs to upgrade or reconfigure its system, the Interconnection Customer will not be responsible for the cost of new or additional equipment beyond the point of common coupling between the Interconnection Customer and the Utility.

V. ACCESS

5.1 Access to Premises: The Utility shall have access to the disconnect switch of the Unit at all times. At reasonable hours and upon reasonable notice consistent with Section III of this Agreement, or at any time without notice in the event of an emergency (as defined in paragraph 4.1), the Utility shall have access to the Premises.

5.2 Utility and Interconnection Customer Representatives: The Utility shall designate, and shall provide to the Interconnection Customer, the name and telephone number of a representative or representatives who can be reached at all times to allow the Interconnection Customer to report an emergency and obtain the assistance of the Utility. For the purpose of allowing access to the premises, the Interconnection Customer shall provide the Utility with the name and telephone number of a person who is responsible for providing access to the Premises.

5.3 Utility Right to Access Utility-Owned Facilities and Equipment: If necessary for the purposes of this Agreement, the Interconnection Customer shall allow the Utility access to the Utility's equipment and facilities located on the Premises. To the extent that the Interconnection Customer does not own all or any part of the property on which the Utility is required to locate its equipment or facilities to serve the Interconnection Customer under this Agreement, the Interconnection Customer shall secure and provide in favor of the Utility the necessary rights to obtain access to such equipment or facilities, including easements if the circumstances so require.

VI. DISPUTE RESOLUTION

6.1 Good Faith Resolution of Disputes: Each Party agrees to attempt to resolve all disputes arising hereunder promptly, equitably and in a good faith manner.

6.2 Mediation: If a dispute arises under this Agreement, and if it cannot be resolved by the Parties within ten (10) business days after written notice of the dispute, the parties agree to submit the dispute to mediation by a mutually acceptable mediator, in a mutually convenient location in New York State, in accordance with the then current International Institute for Conflict prevention & Resolution Procedure, or to mediation by a mediator provided by the New York Public Service Commission. The Parties agree to participate in good faith in the mediation for a period of up to 90 days. If the Parties are not successful in resolving their disputes through mediation, then the parties may refer the dispute for resolution to the New York Public Service Commission, which shall maintain continuing jurisdiction over this Agreement.

6.3 Escrow: If there are amounts in dispute of more than two thousand dollars ($2,000), the Interconnection Customer shall either place such disputed amounts into an independent escrow account pending final resolution of the dispute in question, or provide to the Utility an appropriate irrevocable standby letter of credit in lieu thereof.

VII. INSURANCE

7.1. Commercial General Liability: The Interconnection Customer shall, at its own expense, procure and maintain throughout the period of this Agreement the following minimum insurance coverage:

7.1.1. Commercial general liability insurance with limits not less than:

7.1.1.1. Five million dollars ($5,000,000) for each occurrence and in the aggregate if the AC Nameplate rating of the Interconnection Customer's Facility is greater than five (5) MWAC;

7.1.1.2. Two million dollars ($2,000,000) for each occurrence and five million dollars ($5,000,000) in the aggregate if the AC Nameplate rating of the Interconnection Customer's Facility is greater than one (1) MWAC and less than or equal to five (5) MWAC;

7.1.1.3. One million dollars ($1,000,000) for each occurrence and in the aggregate if the AC Nameplate rating of the Interconnection Customer's Facility is greater than or equal to 300 (kWAC) and less than or equal to one (1) MWAC

7.1.2. Any combination of general liability and umbrella/excess liability policy limits can be used to satisfy the limit requirements of Section 7.1.1.

7.1.3. The general liability insurance required to be purchased in Section 7.1.1 may be purchased for the direct benefit of the Utility and shall respond to third party claims asserted against the Utility (hereinafter known as "Owners Protective Liability"). Should this option be chosen, the requirement of Section 7.3(a) will not apply but the Owners Protective Liability policy will be purchased for the direct benefit of the Utility and the Utility will be designated as the primary and "Named Insured" under the policy.

7.2. General Commercial Liability Insurance: The Interconnection Customer is not required to provide general commercial liability insurance for facilities with an AC nameplate rating of 300 kW or less. Due to the risk of incurring damages however, the New York State Public Service Commission ("Commission") recommends that the Interconnection Customer obtain adequate insurance. The inability of the Utility to require the Interconnection Customer to provide general commercial liability insurance coverage for operation of the Unit is not a waiver of any rights the Utility may have to pursue remedies at law against the Interconnection Customer to recover damages.

7.3. Insurer Requirements and Endorsements: All required insurance shall be written by reputable insurers authorized to conduct business in New York. In addition, all general liability insurance shall, (a) include the Utility as an additional insured; (b) contain a severability of interest clause or cross-liability clause; (c) provide that the Utility shall not incur liability to the insurance carrier for payment of premium for such insurance; and (d) provide for thirty (30) calendar days' written notice to the Utility prior to cancellation or termination of such insurance, with the exception of a ten (10) days' notice in the event of premium non-payment; provided that to the extent the Interconnection Customer is satisfying the requirements of subpart (d) of this paragraph by means of a presently existing insurance policy, the Interconnection Customer shall only be required to make good faith efforts to satisfy that requirement and will assume the responsibility for notifying the Utility as required above.

7.4. Evidence of Insurance: Evidence of the insurance required shall state that coverage provided is primary and is not in excess to or contributing with any insurance or self-insurance maintained by Interconnecting Customer. Prior to the Utility commencing work on System Modifications, and annually thereafter, the Interconnection Customer shall have its insurer furnish to the Utility certificates of insurance evidencing the insurance coverage required above.

> **7.4.1** If coverage is on a claims-made basis, the Interconnection Customer agrees that the policy effective date or retroactive date shall be no later than the effective date of this agreement, be continuously maintained throughout the life of this agreement, and remain in place for a minimum of three (3) years following the termination of this agreement or if policies are terminated will purchase a three-year extended reporting period. Evidence of such coverage will be provided on an annual basis.
>
> **7.4.2** In the event that an Owners Protective Liability policy is provided, the original policy shall be provided to the Utility.

7.5. Self-Insurance: If the Interconnection Customer has a self-insurance program established in accordance with commercially acceptable risk management practices, the Interconnection Customer may comply with the following in lieu of the above requirements as reasonably approved by the Utility:

> **7.5.1.** The Interconnection Customer shall provide to the Utility, at least thirty (30) calendar days prior to the Date of Initial Operation, evidence of such program to self-insure to a level of coverage equivalent to that required.

7.5.2. If the Interconnection Customer ceases to self-insure to the standards required hereunder, or if the Interconnection Customer is unable to provide continuing evidence of the Interconnection Customer's financial ability to self-insure, the Interconnection Customer agrees to promptly obtain the coverage required under Section 7.1.

7.6. Utility Obligation to Maintain Insurance: The Utility agrees to maintain general liability insurance or self-insurance consistent with its existing commercial practice. Such insurance or self-insurance shall not exclude coverage for the Utility's liabilities undertaken pursuant to this Agreement.

7.7. Notification Obligations: The Parties further agree to notify each other whenever an accident or incident occurs resulting in any injuries or damages that are included within the scope of coverage of such insurance, whether or not such coverage is sought.

VIII. LIMITATION OF LIABILITY

8.1 Each Party's liability to the other Party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any indirect, special, consequential, or punitive damages of any kind whatsoever. Nothing herein is meant to limit the liability of a Party to an unaffiliated third-party claimant.

IX. INDEMNITY

9.1 This provision protects each Party from liability incurred to third parties arising from actions taken pursuant to the provisions of this Agreement. Liability under this provision is exempt from the general limitations on liability found in Section 7.

9.2 Each Party (the "Indemnifying Party") shall at all times indemnify, defend, and hold the other Party (the "Indemnified Party") harmless from any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, to the extent arising out of or resulting from the Indemnifying Party's action or failure to meet its obligations under this Agreement, except in cases of negligence, gross negligence or intentional wrongdoing by the Indemnified Party.

9.3 If a Party is obligated to indemnify and hold the Indemnified Party harmless under this section, the amount owing to the Indemnified Party shall be the amount of such Indemnified Party's actual loss, as adjudicated by the Indemnifying Party's insurance carrier, net of any insurance or other recovery.

9.4 Promptly after receipt by an Indemnified Party of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this section may apply, the Indemnified Party shall notify the Indemnifying Party of such fact. Any unintentional failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the Indemnifying Party.

X. CONSEQUENTIAL DAMAGES

10.1 Other than as expressly provided for in this Agreement or pursuant to the utility tariff, neither Party shall be liable to the other Party under any provision of this Agreement for any losses, damages, costs, or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

XI. MISCELLANEOUS PROVISIONS

11.1 Beneficiaries: This Agreement is intended solely for the benefit of the Parties hereto, and if a Party is an agent, its principal. Nothing in this Agreement shall be construed to create any duty to, or standard of care with reference to, or any liability to, any other person.

11.2 Severability: If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction, such portion or provision shall be deemed separate and independent, and the remainder of this Agreement shall remain in full force and effect.

11.3 Entire Agreement: This Agreement constitutes the entire Agreement between the Parties and supersedes all prior agreements or understandings, whether verbal or written.

11.4 Waiver: No delay or omission in the exercise of any right under this Agreement shall impair any such right or shall be taken, construed or considered as a waiver or relinquishment thereof, but any such right may be exercised from time to time and as often as may be deemed expedient. In the event that any agreement or covenant herein shall be breached and thereafter waived, such waiver shall be limited to the particular breach so waived and shall not be deemed to waive any other breach hereunder.

11.5 Applicable Law: This Agreement shall be governed by and construed in accordance with the law of the State of New York.

11.6 Amendments: This Agreement shall not be amended unless the amendment is in writing and signed by the Utility and the Customer.

11.7 Force Majeure: For purposes of this Agreement, "Force Majeure Event" means any event: (a) that is beyond the reasonable control of the affected Party; and (b) that the affected Party is unable to prevent or provide against by exercising reasonable diligence, including the following events or circumstances, but only to the extent they satisfy the preceding requirements: acts of war, public disorder, insurrection, or rebellion; floods, hurricanes, earthquakes, lightning, storms, and other natural calamities; explosions or fires; strikes, work stoppages, or labor disputes; embargoes; and sabotage. If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, such Party will promptly notify the other Party in writing, and will keep the other Party informed on a continuing basis of the scope and duration of the Force Majeure Event. The affected Party will specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the affected Party is taking to mitigate the effects of the event on its performance. The affected Party will be entitled to suspend or modify its performance of obligations under this Agreement, other than the obligation to make payments then due or becoming due under this Agreement, but only to the extent that the effect of the Force Majeure Event cannot be mitigated by the use of reasonable efforts. The affected Party will use reasonable efforts to resume its performance as soon as possible.

11.8 Assignment to Corporate Party: At any time during the term, the Interconnection Customer may assign this Agreement to a corporation or other entity with limited liability, provided that the Interconnection Customer obtains the consent of the Utility. Such consent will not be withheld unless the Utility can demonstrate that the corporate entity is not reasonably capable of performing the obligations of the assigning Interconnection Customer under this Agreement.

11.9 Assignment to Individuals: At any time during the term, the Interconnection Customer may assign this Agreement to another person, other than a corporation or other entity with limited liability, provided that the assignee is the owner, lessee, or is otherwise responsible for the Unit.

11.10 Permits and Approvals: Interconnection Customer shall obtain all environmental and other permits lawfully required by governmental authorities prior to the construction and for the operation of the Unit during the term of this Agreement.

11.11 Limitation of Liability: Neither by inspection, if any, or non-rejection, nor in any other way, does the Utility give any warranty, express or implied, as to the adequacy, safety, or other characteristics of any structures, equipment, wires, appliances or devices owned, installed or maintained by the Interconnection Customer or leased by the Interconnection Customer from third parties, including without limitation the Unit and any structures, equipment, wires, appliances or devices appurtenant thereto.

ACCEPTED AND AGREED:

Interconnection Customer

Signature:

Printed Name:

Title:

Date:

Utility Signature:

Printed Name:

Title:

Date:

ATTACHMENT 1

ENERGY STORAGE SYSTEMS DESCRIPTION OF OPERATING PARAMETERS AND LIMITS

APPENDIX A-1 – FOR USE WITH FEDERAL AGENCIES

NEW YORK STATE STANDARDIZED CONTRACT FOR INTERCONNECTION OF NEW DISTRIBUTED GENERATION UNITSAND/OR ENERGY STORAGE SYSTEMS WITH CAPACITY OF 5 MW OR LESS CONNECTED IN PARALLEL WITH UTILITY DISTRIBUTION SYSTEMS

Interconnection Customer Information:	**Utility Information:**
Name:	Name:
Address:	Address:
Telephone:	Telephone:
Fax:	Fax:
Email:	Email:
Unit Application/File No.:	Utility Account Number:

DEFINITIONS

Delivery Service means the services the Utility may provide to deliver capacity or energy generated by the Interconnection Customer to a buyer to a delivery point(s), including related ancillary services.

Energy Storage System (ESS) means a commercially available mechanical, electrical, or electro-chemical means to store and release electrical energy, and its associated electrical inversion device and control functions that may be stand-alone or paired with a distributed generator at a point of common coupling.

Interconnection Customer means that the owner of the Unit is a Federal agency, defined by the Federal Claims Act, 28 U.S.C. 2671 et seq., to include the executive departments, the judicial and legislative branches, the military departments, independent establishments of the United States, and corporations primarily acting as instrumentalities or agencies of the United States, but does not include any contractor with the United States (U.S.).

Interconnection Facilities means the equipment and facilities on the Utility's system necessary to permit operation of the Unit in parallel with the Utility's system.

Material Modification means a Modification to a Unit that may have adverse impacts on the Utility's system, Utility customers, other projects, or applications in the interconnection queue.

Modification means a change to the ownership, equipment, equipment ratings, equipment configuration, or operating conditions of the Unit.

Premises means the real property where the Unit is located.

SIR means the New York State Standardized Interconnection Requirements for new distributed generation units with a nameplate capacity of 5 MW or less connected in parallel with the Utility's distribution system.

Unit means the distributed generation, stand-alone ESS, or combined generation and ESS facilities approved by the Utility for operation in parallel with the Utility's system. This Agreement relates only to such Unit, but a new agreement shall not be required if the Interconnection Customer makes physical alterations to the Unit that do not result in an increase in its nameplate generating capacity. The nameplate generating capacity or inverter/converter rating of the Unit shall not exceed 5 MW.

Utility means [insert legal name of the interconnecting utility].

I. TERM AND TERMINATION

1.1 Term: This Agreement shall become effective when executed by both Parties and shall continue in effect until terminated.

1.2 Termination: This Agreement may be terminated as follows:

a. The Interconnection Customer may terminate this Agreement at any time, by giving the Utility sixty (60) days' written notice.

b. Failure by the Interconnection Customer to seek final acceptance by the Utility within twelve (12) months after completion of the utility construction process described in the SIR shall automatically terminate this Agreement.

c. Either Party may, by giving the other Party at least sixty (60) days' prior written notice, terminate this Agreement in the event that the other Party is in default of any of the material terms and conditions of this Agreement. The terminating Party shall specify in the notice the basis for the termination and shall provide a reasonable opportunity to cure the default.

d. The Utility may, by giving the Interconnection Customer at least sixty (60) days' prior written notice, terminate this Agreement for cause. The Interconnection Customer's non-compliance with an upgrade to the SIR, unless the Interconnection Customer's installation is "grandfathered," shall constitute good cause.

1.3 Disconnection and Survival of Obligations: Upon termination of this Agreement the Unit will be disconnected from the Utility's electric system. The termination of this Agreement shall not relieve either Party of its liabilities and obligations, owed or continuing at the time of the termination.

1.4 Suspension: This Agreement will be suspended during any period in which the Interconnection Customer is not eligible for Delivery Service from the Utility

II. SCOPE OF AGREEMENT

2.1 Scope of Agreement: This Agreement relates solely to the conditions under which the Utility and the Interconnection Customer agree that the Unit may be interconnected to and operated in parallel with the Utility's system.

III. Electricity Not Covered

The Utility shall have no duty under this Agreement to account for, pay for, deliver, or return in kind any electricity produced by the Facility and delivered into the Utility's System unless the system is net metered as described in Public Service Law Section 66-l.

IV. INSTALLATION, OPERATION AND MAINTENANCE OF UNIT

3.1 Compliance with SIR: Subject to the provisions of this Agreement, the Utility shall be required to interconnect the Unit to the Utility's system, for purposes of parallel operation, if the Utility accepts the Unit as in compliance with the SIR. The Interconnection Customer shall have a continuing obligation to maintain and operate the Unit in compliance with the SIR.

3.2 Observation of the Unit - Construction Phase: The Utility may, in its discretion and upon reasonable notice, perform reasonable on-site verifications during the construction of the Unit. Whenever the Utility chooses to exercise its right to perform observations herein it shall specify to the Interconnection Customer its reasons for its decision to perform the observation. For purposes of this paragraph and paragraphs 3.3 through 3.5, the term "on-site verification" shall not include testing of the Unit, and verification tests shall not be required except as provided in paragraphs

3.3 Observation of the Unit - Ten-day Period: The Utility may perform on-site verifications of the Unit and observe the execution of verification testing within a reasonable period of time, not exceeding ten (10) business days after system installation. The Unit will be allowed to commence parallel operation upon satisfactory completion of the verification test. The Interconnection Customer must have complied with and must continue to comply with all contractual and technical requirements.

3.4 Observation of the Unit - Post-Ten-day Period: If the Utility does not perform an on-site verification of the Unit and observe the execution of verification testing within the ten-day period, the Interconnection Customer will send the Utility within five (5) days of the verification testing a written notification certifying that the Unit has been installed and tested in compliance with the SIR, the utility-accepted design and the equipment manufacturer's instructions. The Interconnection Customer may begin to produce energy upon satisfactory completion of the verification test. After receiving the verification test notification, the Utility will either issue to the Interconnection Customer a formal letter of acceptance for interconnection, or may request that the applicant and utility set a date and time to perform an on-site verification of the Unit and make reasonable inquiries of the Interconnection Customer, but only for purposes of determining whether the verification tests were properly performed. The Interconnection Customer shall not be required to perform the verification tests a second time, unless irregularities appear in the verification test report or there are other objective indications that the tests were not properly performed in the first instance.

3.5 Observation of the Unit - Operations: The Utility may perform on-site verification of the operations of the Unit after it commences operations if the Utility has a reasonable basis for doing so based on its responsibility to provide continuous and reliable utility service or as authorized by the provisions of the Utility's Retail Electric Tariff relating to the verification of Interconnection Customer installations generally.

3.6 Costs of Interconnection Facilities: During the term of this Agreement, the Utility shall design, construct and install the Interconnection Facilities. The Interconnection Customer shall be responsible for paying the incremental capital cost of such Interconnection Facilities attributable to the Interconnection Customer's Unit. All costs associated with the operation and maintenance of the Dedicated Facilities after the Unit first produces energy shall be the responsibility of the Utility.

3.7 Modifications to the Unit: The Interconnection Customer may request a Modification at any time after commencement of parallel operation. The Utility shall evaluate the request and determine whether the proposed change is a Material Modification in accordance with the rules for requesting changes to applications in the SIR. A Material Modification will be studied pursuant to the procedures in the SIR for new applications. In the case of a non-material modification that is accepted by the Utility, the parties will execute an amendment to this Agreement describing the Unit changes that have been approved.

V. **DISCONNECTION OF THE UNIT**

4.1 Emergency Disconnection: The Utility may disconnect the Unit, without prior notice to the Interconnection Customer (a) to eliminate conditions that constitute a potential hazard to Utility personnel or the general public; (b) if pre-emergency or emergency conditions exist on the Utility system; (c) if a hazardous condition relating to the Unit is observed by a Utility inspection; or (d) if the Interconnection Customer has tampered with any protective device. The Utility shall notify the Interconnection Customer of the emergency if circumstances permit. The Interconnection Customer shall notify the Utility promptly when it becomes aware of an emergency condition that affects the Unit that may reasonably be expected to affect the Utility EPS.

4.2 Non-Emergency Disconnection Due to Unit Performance: The Utility may disconnect the Unit, after notice to the responsible party has been provided and a reasonable time to correct, consistent with the conditions, has elapsed, if (a) the Interconnection Customer has failed to make available records of verification tests and maintenance of his protective devices; (b) the Unit system interferes with Utility equipment or equipment belonging to other customers of the Utility; (c) the Unit adversely affects the quality of service of adjoining customers; (d) the ESS does not operate in compliance with the operating parameters and limits described in Attachment 1 to this Agreement.

4.3 Non-Emergency Disconnection for Utility Work: The Utility may disconnect the Unit after notice to Interconnection Customer when necessary for routine maintenance, construction, and repairs on the Utility EPS. The Interconnection Customer may request to reconnect its service prior to the completion of the Utility's work. The Utility shall accommodate such requests, provided that the Interconnection Customer shall be responsible for the costs of the Utility's review and any system modifications required to reconnect the Unit ahead of schedule.

4.4 Disconnection by Interconnection Customer: The Interconnection Customer may disconnect a Unit with an AC nameplate rating above 300 kW upon 18 hours advance notice to the Utility if the planned shutdown will last 8 hours or more. For non-emergency forced outages lasting 8 hours or more, the Interconnection Customer shall notify the Utility within 24 hours of the commencement of the shutdown

4.5 Utility Obligation to Cure Adverse Effect: If, after the Interconnection Customer meets all interconnection requirements, the operations of the Utility are adversely affecting the performance of the Unit or the Customer's premises, the Utility shall immediately take appropriate action to eliminate the adverse effect. If the Utility determines that it needs to upgrade or reconfigure its system, the Interconnection Customer will not be responsible for the cost of new or additional equipment beyond the point of common coupling between the Interconnection Customer and the Utility.

VI. **ACCESS**

5.1 Access to Premises: The Utility shall have access to the disconnect switch of the Unit at all times. At reasonable hours and upon reasonable notice consistent with Section III of this Agreement, or at any time without notice in the event of an emergency (as defined in paragraph 4.1), the Utility shall have access to the Premises.

5.2 Utility and Interconnection Customer Representatives: The Utility shall designate, and shall provide to the Interconnection Customer, the name and telephone number of a representative or representatives who can be reached at all times to allow the Interconnection Customer to report an emergency and obtain the assistance of the Utility. For the purpose of allowing access to the premises, the Interconnection Customer shall provide the Utility with the name and telephone number of a person who is responsible for providing access to the Premises.

5.3 Utility Right to Access Utility-Owned Facilities and Equipment: If necessary for the purposes of this Agreement, the Interconnection Customer shall allow the Utility access to the Utility's equipment and facilities located on the Premises. To the extent that the Interconnection Customer does not own all or any part of the property on which the Utility is required to locate its equipment or facilities to serve the Interconnection Customer under this Agreement, the Interconnection Customer shall secure and provide in favor of the Utility the necessary rights to obtain access to such equipment or facilities, including easements if the circumstances so require.

VII. **DISPUTE RESOLUTION**

6.1 Good Faith Resolution of Disputes: Each Party agrees to attempt to resolve all disputes arising hereunder promptly, equitably and in a good faith manner.

6.2 Mediation: If a dispute arises under this Agreement, and if it cannot be resolved by the Parties within ten (10) business days after written notice of the dispute, the parties agree to submit the dispute to mediation by a mutually acceptable mediator, in a mutually convenient location in New York State, in accordance with the then current International Institute for Conflict prevention & Resolution Procedure, or to mediation by a mediator provided by the New York Public Service Commission. The Parties agree to participate in good faith in the mediation for a period of up to 90 days. If the Parties are not successful in resolving their disputes through mediation, then the parties may refer the dispute for resolution to the New York Public Service Commission, which shall maintain continuing jurisdiction over this Agreement.

6.3 Escrow: If there are amounts in dispute of more than two thousand dollars ($2,000), the Interconnection Customer shall, within 30 working days of written request from the Utility and subject to the availability of appropriations, provide the Utility with a Letter of Assurance confirming that the Interconnection Customer (a U.S. Federal Agency) has adequate funds available under the full faith and credit of the United States to cover the potential costs of the dispute, if it is resolved in the Utility's favor.

VIII. INSURANCE

7.1 Self-Insurance: The Interconnection Customer is self-insured as an agency of the United States of America pursuant to the Federal Tort Claims Act, 28 U.S.C. 2671 *et seq*.

7.2 Utility Obligation to Maintain Insurance: The Utility agrees to maintain general liability insurance or self-insurance consistent with its existing commercial practice. Such insurance or self-insurance shall not exclude coverage for the Utility's liabilities undertaken pursuant to this Agreement.

7.3 Notification Obligations: The Parties further agree to notify each other whenever an accident or incident occurs resulting in any injuries or damages that are included within the scope of coverage of such insurance, whether or not such coverage is sought.

IX. LIMITATION OF LIABILITY

8.1 Each Party's liability to the other Party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any indirect, special, consequential, or punitive damages of any kind whatsoever. Nothing herein is meant to limit the liability of a Party to an unaffiliated third-party claimant. The liability, if any, of the Interconnection Customer for injury or loss of property, or personal injury or death shall be governed exclusively by the provisions of the Federal Tort Claims Act, 28 U.S.C. 2671, *et seq*.

X. INDEMNITY

The liability, if any, of the Interconnection Customer for injury or loss of property, or personal injury or death shall be governed exclusively by the provisions of the Federal Tort Claims Act, 28 U.S.C. 1346(b).

a. Each Party (the "Indemnifying Party") shall at all times indemnify, defend, and hold the other Party (the "Indemnified Party") harmless from any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, to the extent arising out of or resulting from the Indemnifying Party's action or failure to meet its obligations under this Agreement, except in cases of negligence, gross negligence or intentional wrongdoing by the Indemnified Party.

b. If a Party is obligated to indemnify and hold the Indemnified Party harmless under this section, the amount owing to the Indemnified Party shall be the amount of such Indemnified Party's actual loss, as adjudicated by the Indemnifying Party's insurance carrier, net of any insurance or other recovery.

c. Promptly after receipt by an Indemnified Party of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this section may apply, the Indemnified Party shall notify the Indemnifying Party of such fact. Any unintentional failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the Indemnifying Party.

XI. CONSEQUENTIAL DAMAGES

Other than as expressly provided for in this Agreement or pursuant to the utility tariff, neither Party shall be liable to the other Party under any provision of this Agreement for any losses, damages, costs, or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

XII. MISCELLANEOUS PROVISIONS

11.1 Beneficiaries: This Agreement is intended solely for the benefit of the Parties hereto, and if a Party is an agent, its principal. Nothing in this Agreement shall be construed to create any duty to, or standard of care with reference to, or any liability to, any other person.

11.2 Severability: If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction, such portion or provision shall be deemed separate and independent, and the remainder of this Agreement shall remain in full force and effect.

11.3 Entire Agreement: This Agreement constitutes the entire Agreement between the Parties and supersedes all prior agreements or understandings, whether verbal or written.

11.4 Waiver: No delay or omission in the exercise of any right under this Agreement shall impair any such right or shall be taken, construed or considered as a waiver or relinquishment thereof, but any such right may be exercised from time to time and as often as may be deemed expedient. In the event that any agreement or covenant herein shall be breached and thereafter waived, such waiver shall be limited to the particular breach so waived and shall not be deemed to waive any other breach hereunder.

11.5 Applicable Law: This Agreement shall be governed by the laws of the United States of America and, to the extent that there is no applicable or controlling federal law, the laws of the State of New York, without regard to conflicts of law principles.

11.6 Amendments: This Agreement shall not be amended unless the amendment is in writing and signed by the Utility and the Customer.

11.7 Force Majeure: For purposes of this Agreement, "Force Majeure Event" means any event: (a) that is beyond the reasonable control of the affected Party; and (b) that the affected Party is unable to prevent or provide against by exercising reasonable diligence, including the following events or circumstances, but only to the extent they satisfy the preceding requirements: acts of war, public disorder, insurrection, or rebellion; floods, hurricanes, earthquakes, lightning, storms, and other natural calamities; explosions or fires; strikes, work stoppages, or labor disputes; embargoes; and sabotage. If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, such Party will promptly notify the other Party in writing, and will keep the other Party informed on a continuing basis of the scope and duration of the Force Majeure Event. The affected Party will specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the affected Party is taking to mitigate the effects of the event on its performance. The affected Party will be entitled to suspend or modify its performance of obligations under this Agreement, other than the obligation to make payments then due or becoming due under this Agreement, but only to the extent that the effect of the Force Majeure Event cannot be mitigated by the use of reasonable efforts. The affected Party will use reasonable efforts to resume its performance as soon as possible.

11.8 Assignment to Corporate Party: At any time during the term, the Interconnection Customer may assign this Agreement to a corporation or other entity with limited liability, provided that the Interconnection Customer obtains the consent of the Utility. Such consent will not be withheld unless the Utility can demonstrate that the corporate entity is not reasonably capable of performing the obligations of the assigning Interconnection Customer under this Agreement.

11.9 Assignment to Individuals: At any time during the term, the Interconnection Customer may assign this Agreement to another person, other than a corporation or other entity with limited liability, provided that the assignee is the owner, lessee, or is otherwise responsible for the Unit.

11.10 Permits and Approvals: Interconnection Customer shall obtain all environmental and other permits lawfully required by governmental authorities prior to the construction and for the operation of the Unit during the term of this Agreement.

Limitation of Liability: Neither by inspection, if any, or non-rejection, nor in any other way, does the Utility give any warranty, express or implied, as to the adequacy, safety, or other characteristics of any structures, equipment, wires, appliances or devices owned, installed or maintained by the Interconnection Customer or leased by the Interconnection Customer from third parties, including without limitation the Unit and any structures, equipment, wires, appliances or devices appurtenant thereto. The liability, if any, of the Interconnection Customer for injury or loss of property, or personal injury or death shall be governed exclusively by the provisions of the Federal Tort Claims Act, 28 U.S.C. 2671, *et seq*.

ACCEPTED AND AGREED:

Interconnection Customer

Signature:

Printed Name:

Title:

Date:

Utility Signature:

Printed Name:

Title:

Date:

ATTACHMENT 1

ENERGY STORAGE SYSTEMS DESCRIPTION OF OPERATING PARAMETERS AND LIMITS

APPENDIX A-2 – FOR USE WITH STATE AGENCIES

NEW YORK STATE STANDARDIZED CONTRACT FOR INTERCONNECTION OF NEW DISTRIBUTED GENERATION UNITS AND/OR ENERGY STORAGE SYSTEMS WITH CAPACITY OF 5 MW OR LESS CONNECTED IN PARALLEL WITH UTILITY DISTRIBUTION SYSTEMS

Interconnection Customer Information:	**Utility Information:**
Name:	Name:
Address:	Address:
Telephone:	Telephone:
Fax:	Fax:
Email:	Email:
Unit Application/File No.:	Utility Account Number:

DEFINITIONS

Delivery Service means the services the Utility may provide to deliver capacity or energy generated by the Interconnection Customer to a buyer to a delivery point(s), including related ancillary services.

Energy Storage System (ESS) means a commercially available mechanical, electrical, or electro-chemical means to store and release electrical energy, and its associated electrical inversion device and control functions that may be stand-alone or paired with a distributed generator at a point of common coupling.

Interconnection Customer means the State Agency that is the owner of the Unit.

Interconnection Facilities means the equipment and facilities on the Utility's system necessary to permit operation of the Unit in parallel with the Utility's system.

Material Modification means a Modification to a Unit that may have adverse impacts on the Utility's system, Utility customers, other projects, or applications in the interconnection queue.

Modification means a change to the ownership, equipment, equipment ratings, equipment configuration, or operating conditions of the Unit.

Premises means the real property where the Unit is located.

SIR means the New York State Standardized Interconnection Requirements for new distributed generation units with a nameplate capacity of 5 MW or less connected in parallel with the Utility's distribution system.

State Agency means any state department, state university of New York, city university of New York, board, bureau, division, commission, committee, council, office, or other governmental entity performing a governmental or proprietary function for the state, or any combination thereof, except any public authority or public benefit corporation, the judiciary, or the state legislature.

Unit means the distributed generation, stand-alone ESS, or combined generation and ESS facilities approved by the Utility for operation in parallel with the Utility's system. This Agreement relates only to such Unit, but a new agreement shall not be required if the Interconnection Customer makes physical alterations to the Unit that do not result in an increase in its nameplate generating capacity. The nameplate generating capacity or inverter/converter rating of the Unit shall not exceed 5 MW.

Utility means [insert legal name of the interconnecting utility].

I. TERM AND TERMINATION

1.1 Term: This Agreement shall become effective when executed by both Parties and shall continue in effect until terminated.

1.2 Termination: This Agreement may be terminated as follows:

a. The Interconnection Customer may terminate this Agreement at any time, by giving the Utility sixty (60) days' written notice.

b. Failure by the Interconnection Customer to seek final acceptance by the Utility within twelve (12) months after completion of the utility construction process described in the SIR shall automatically terminate this Agreement.

c. Either Party may, by giving the other Party at least sixty (60) days' prior written notice, terminate this Agreement in the event that the other Party is in default of any of the material terms and conditions of this Agreement. The terminating Party shall specify in the notice the basis for the termination and shall provide a reasonable opportunity to cure the default.

d. The Utility may, by giving the Interconnection Customer at least sixty (60) days' prior written notice, terminate this Agreement for cause. The Interconnection Customer's non-compliance with an upgrade to the SIR, unless the Interconnection Customer's installation is "grandfathered," shall constitute good cause.

1.3 Disconnection and Survival of Obligations: Upon termination of this Agreement the Unit will be disconnected from the Utility's electric system. The termination of this Agreement shall not relieve either Party of its liabilities and obligations, owed or continuing at the time of the termination.

1.4 Suspension: This Agreement will be suspended during any period in which the Interconnection Customer is not eligible for Delivery Service from the Utility

II. SCOPE OF AGREEMENT

2.1 Scope of Agreement: This Agreement relates solely to the conditions under which the Utility and the Interconnection Customer agree that the Unit may be interconnected to and operated in parallel with the Utility’s system.

2.2 Electricity Not Covered: The Utility shall have no duty under this Agreement to account for, pay for, deliver, or return in kind any electricity produced by the Facility and delivered into the Utility’s System unless the system is net metered as described in Public Service Law Section 66-J.

III. INSTALLATION, OPERATION AND MAINTENANCE OF UNIT

3.1 Compliance with SIR: Subject to the provisions of this Agreement, the Utility shall be required to interconnect the Unit to the Utility's system, for purposes of parallel operation, if the Utility accepts the Unit as in compliance with the SIR. The Interconnection Customer shall have a continuing obligation to maintain and operate the Unit in compliance with the SIR.

3.2 Observation of the Unit - Construction Phase: The Utility may, in its discretion and upon reasonable notice, perform reasonable on-site verifications during the construction of the Unit. Whenever the Utility chooses to exercise its right to perform observations herein it shall specify to the Interconnection Customer its reasons for its decision to perform the observation. For purposes of this paragraph and paragraphs 3.3 through 3.5, the term "on-site verification" shall not include testing of the Unit, and verification tests shall not be required except as provided in paragraphs

3.3 Observation of the Unit - Ten-day Period: The Utility may perform on-site verifications of the Unit and observe the execution of verification testing within a reasonable period of time, not exceeding ten (10) business days after system installation. The Unit will be allowed to commence parallel operation upon satisfactory completion of the verification test. The Interconnection Customer must have complied with and must continue to comply with all contractual and technical requirements.

3.4 Observation of the Unit - Post-Ten-day Period: If the Utility does not perform an on-site verification of the Unit and observe the execution of verification testing within the ten-day period, the Interconnection Customer will send the Utility within five (5) days of the verification testing a written notification certifying that the Unit has been installed and tested in compliance with the SIR, the utility-accepted design and the equipment manufacturer's instructions. The Interconnection Customer may begin to produce energy upon satisfactory completion of the verification test. After receiving the verification test notification, the Utility will either issue to the Interconnection Customer a formal letter of acceptance for interconnection, or may request that the applicant and utility set a date and time to perform an on-site verification of the Unit and make reasonable inquiries of the Interconnection Customer, but only for purposes of determining whether the verification tests were properly performed. The Interconnection Customer shall not be required to perform the verification tests a second time, unless irregularities appear in the verification test report or there are other objective indications that the tests were not properly performed in the first instance.

3.5 Observation of the Unit - Operations: The Utility may perform on-site verification of the operations of the Unit after it commences operations if the Utility has a reasonable basis for doing so based on its responsibility to provide continuous and reliable utility service or as authorized by the provisions of the Utility's Retail Electric Tariff relating to the verification of Interconnection Customer installations generally.

3.6 Costs of Interconnection Facilities: During the term of this Agreement, the Utility shall design, construct and install the Interconnection Facilities. The Interconnection Customer shall be responsible for paying the incremental capital cost of such Interconnection Facilities attributable to the Interconnection Customer's Unit. All costs associated with the operation and maintenance of the Dedicated Facilities after the Unit first produces energy shall be the responsibility of the Utility.

3.7 Modifications to the Unit: The Interconnection Customer may request a Modification at any time after commencement of parallel operation. The Utility shall evaluate the request and determine whether the proposed change is a Material Modification in accordance with the rules for requesting changes to applications in the SIR. A Material Modification will be studied pursuant to the procedures in the SIR for new applications. In the case of a non-material modification that is accepted by the Utility, the parties will execute an amendment to this Agreement describing the Unit changes that have been approved.

IV. DISCONNECTION OF THE UNIT

4.1 Emergency Disconnection: The Utility may disconnect the Unit, without prior notice to the Interconnection Customer (a) to eliminate conditions that constitute a potential hazard to Utility personnel or the general public; (b) if pre-emergency or emergency conditions exist on the Utility system; (c) if a hazardous condition relating to the Unit is observed by a Utility inspection; or (d) if the Interconnection Customer has tampered with any protective device. The Utility shall notify the Interconnection Customer of the emergency if circumstances permit. The Interconnection Customer shall notify the Utility promptly when it becomes aware of an emergency condition that affects the Unit that may reasonably be expected to affect the Utility EPS.

4.2 Non-Emergency Disconnection Due to Unit Performance: The Utility may disconnect the Unit, after notice to the responsible party has been provided and a reasonable time to correct, consistent with the conditions, has elapsed, if (a) the Interconnection Customer has failed to make available records of verification tests and maintenance of his protective devices; (b) the Unit system interferes with Utility equipment or equipment belonging to other customers of the Utility; (c) the Unit adversely affects the quality of service of adjoining customers; (d) the ESS does not operate in compliance with the operating parameters and limits described in Attachment 1 to this Agreement.

4.3 Non-Emergency Disconnection for Utility Work: The Utility may disconnect the Unit after notice to Interconnection Customer when necessary for routine maintenance, construction, and repairs on the Utility EPS. The Interconnection Customer may request to reconnect its service prior to the completion of the Utility's work. The Utility shall accommodate such requests, provided that the Interconnection Customer shall be responsible for the costs of the Utility's review and any system modifications required to reconnect the Unit ahead of schedule.

4.4 Disconnection by Interconnection Customer: The Interconnection Customer may disconnect a Unit with an AC nameplate rating above 300 kW upon 18 hours advance notice to the Utility if the planned shutdown will last 8 hours or more. For non-emergency forced outages lasting 8 hours or more, the Interconnection Customer shall notify the Utility within 24 hours of the commencement of the shutdown

4.5 Utility Obligation to Cure Adverse Effect: If, after the Interconnection Customer meets all interconnection requirements, the operations of the Utility are adversely affecting the performance of the Unit or the Customer's premises, the Utility shall immediately take appropriate action to eliminate the adverse effect. If the Utility determines that it needs to upgrade or reconfigure its system, the Interconnection Customer will not be responsible for the cost of new or additional equipment beyond the point of common coupling between the Interconnection Customer and the Utility.

V. ACCESS

5.1 Access to Premises: The Utility shall have access to the disconnect switch of the Unit at all times. At reasonable hours and upon reasonable notice consistent with Section III of this Agreement, or at any time without notice in the event of an emergency (as defined in paragraph 4.1), the Utility shall have access to the Premises.

5.2 Utility and Interconnection Customer Representatives: The Utility shall designate, and shall provide to the Interconnection Customer, the name and telephone number of a representative or representatives who can be reached at all times to allow the Interconnection Customer to report an emergency and obtain the assistance of the Utility. For the purpose of allowing access to the premises, the Interconnection Customer shall provide the Utility with the name and telephone number of a person who is responsible for providing access to the Premises.

5.3 Utility Right to Access Utility-Owned Facilities and Equipment: If necessary for the purposes of this Agreement, the Interconnection Customer shall allow the Utility access to the Utility's equipment and facilities located on the Premises. To the extent that the Interconnection Customer does not own all or any part of the property on which the Utility is required to locate its equipment or facilities to serve the Interconnection Customer under this Agreement, the Interconnection Customer shall secure and provide in favor of the Utility the necessary rights to obtain access to such equipment or facilities, including easements if the circumstances so require.

VI. DISPUTE RESOLUTION

6.1 Good Faith Resolution of Disputes: Each Party agrees to attempt to resolve all disputes arising hereunder promptly, equitably and in a good faith manner.

6.2 Mediation: If a dispute arises under this Agreement, and if it cannot be resolved by the Parties within ten (10) business days after written notice of the dispute, the parties agree to submit the dispute to mediation by a mutually acceptable mediator, in a mutually convenient location in New York State, in accordance with the then current International Institute for Conflict prevention & Resolution Procedure, or to mediation by a mediator provided by the New York Public Service Commission. The Parties agree to participate in good faith in the mediation for a period of up to 90 days. If the Parties are not successful in resolving their disputes through mediation, then the parties may refer the dispute for resolution to the New York Public Service Commission, which shall maintain continuing jurisdiction over this Agreement.

6.3 **Escrow:** The Interconnection customer shall, within thirty (30) working days of written request from the Utility and subject to the availability of appropriations under §41 of the State Finance Law, provide the Utility with a Letter of Assurance confirming that the Interconnection Customer (a New York State Agency) has adequate funds available under the taxing power and/or full faith and credit of the State of New York to cover the costs in dispute, if it is resolved in the Utility's favor.

VII. INSURANCE

7.1. **Commercial General Liability:** The Interconnection Customer shall, at its own expense, procure and maintain throughout the period of this Agreement the following minimum insurance coverage:

7.1.1. Commercial general liability insurance with limits not less than:

7.1.1.1. Five million dollars ($5,000,000) for each occurrence and in the aggregate if the AC Nameplate rating of the Interconnection Customer's Facility is greater than five (5) MWAC;

7.1.1.2. Two million dollars ($2,000,000) for each occurrence and five million dollars ($5,000,000) in the aggregate if the AC Nameplate rating of the Interconnection Customer's Facility is greater than one (1) MWAC and less than or equal to five (5) MWAC;

7.1.1.3. One million dollars ($1,000,000) for each occurrence and in the aggregate if the AC Nameplate rating of the Interconnection Customer's Facility is greater than or equal to 300 (kWAC) and less than or equal to one (1) MWAC

7.1.2. Any combination of general liability and umbrella/excess liability policy limits can be used to satisfy the limit requirements of Section 7.1.1 (a).

7.1.3. The general liability insurance required to be purchased in Section 7.1 (a) may be purchased for the direct benefit of the Utility and shall respond to third party claims asserted against the Utility (hereinafter known as "Owners Protective Liability"). Should this option be chosen, the requirement of Section 7.3(a) will not apply but the Owners Protective Liability policy will be purchased for the direct benefit of the Utility and the Utility will be designated as the primary and "Named Insured" under the policy.

7.2. **General Commercial Liability Insurance:** The Interconnection Customer is not required to provide general commercial liability insurance for facilities with an AC nameplate rating of 300 kW or less. Due to the risk of incurring damages however, the New York State

Public Service Commission ("Commission") recommends that the Interconnection Customer obtain adequate insurance. The inability of the Utility to require the Interconnection Customer to provide general commercial liability insurance coverage for operation of the Unit is not a waiver of any rights the Utility may have to pursue remedies at law against the Interconnection Customer to recover damages

7.3. Insurer Requirements and Endorsements: All required insurance shall be written by reputable insurers authorized to conduct business in New York. In addition, all general liability insurance shall, (a) include the Utility as an additional insured; (b) contain a severability of interest clause or cross-liability clause; (c) provide that the Utility shall not incur liability to the insurance carrier for payment of premium for such insurance; and (d) provide for thirty (30) calendar days' written notice to the Utility prior to cancellation or termination of such insurance, with the exception of a ten (10) days' notice in the event of premium non-payment; provided that to the extent the Interconnection Customer is satisfying the requirements of subpart (d) of this paragraph by means of a presently existing insurance policy, the Interconnection Customer shall only be required to make good faith efforts to satisfy that requirement and will assume the responsibility for notifying the Utility as required above.

7.4. Evidence of Insurance: Evidence of the insurance required shall state that coverage provided is primary and is not in excess to or contributing with any insurance or self-insurance maintained by Interconnecting Customer. Prior to the Utility commencing work on System Modifications, and annually thereafter, the Interconnection Customer shall have its insurer furnish to the Utility certificates of insurance evidencing the insurance coverage required above.

7.4.1 If coverage is on a claims-made basis, the Interconnection Customer agrees that the policy effective date or retroactive date shall be no later than the effective date of this agreement, be continuously maintained throughout the life of this agreement, and remain in place for a minimum of three (3) years following the termination of this agreement or if policies are terminated will purchase a three-year extended reporting period. Evidence of such coverage will be provided on an annual basis.

7.4.2 In the event that an Owners Protective Liability policy is provided, the original policy shall be provided to the Utility.

7.5. Self-Insurance: If the Interconnection Customer has a self-insurance program established in accordance with commercially acceptable risk management practices or self-retention or funding program established by law or otherwise set by local governmental policy, the Interconnection Customer may comply with the following in lieu of the above requirements as reasonably approved by the Utility:

7.5.1. The Interconnection Customer shall provide to the Utility, at least thirty (30) calendar days prior to the Date of Initial Operation, evidence of such program to self-insure or self-retain to a level of coverage equivalent to that required.

7.5.2. If the Interconnection Customer ceases to self-insure or self-retain or fund to the standards required hereunder, or if the Interconnection Customer is unable to provide continuing evidence of the Interconnection Customer's financial ability to self-insure, the Interconnection Customer agrees to promptly obtain the coverage required under Section 7.1.

7.6. Utility Obligation to Maintain Insurance: The Utility agrees to maintain general liability insurance or self-insurance consistent with its existing commercial practice. Such insurance or self-insurance shall not exclude coverage for the Utility's liabilities undertaken pursuant to this Agreement.

7.7. Notification Obligations: The Parties further agree to notify each other whenever an accident or incident occurs resulting in any injuries or damages that are included within the scope of coverage of such insurance, whether or not such coverage is sought.

VIII. LIMITATION OF LIABILITY

8.1 Each Party's liability to the other Party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either Party be liable to the other Party for any indirect, special, consequential, or punitive damages of any kind whatsoever. Nothing herein is meant to limit the liability of a Party to an unaffiliated third-party claimant.

IX. INDEMNITY

9.1 This provision protects each Party from liability incurred to third parties arising from actions taken pursuant to the provisions of this Agreement. Liability under this provision is exempt from the general limitations on liability found in Section 7.

9.2 The Utility shall at all times indemnify, defend, and hold the Interconnection Customer (State Agency) harmless from any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, to the extent arising out of or resulting from the action or failure to meet its obligations under this Agreement, except in cases of negligence, gross negligence or intentional wrongdoing by the Interconnection Customer .

9.3 Subject to the availability of lawful appropriations and consistent with Section 8 of the State Court of Claims Act, the Interconnection Customer shall hold Utility harmless from and indemnify it for any final judgment of a court of competent jurisdiction to the extent attributable to the negligence of the Interconnection Customer or its officers or employees when acting within the course and scope of their employment. Liability incurred to third parties as a result of carrying out the provisions under this Agreement shall be exempt from the general limitations on liability set forth above.[3]

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3 Certain New York laws (e.g. Section 41 of New York State Finance Law, Article 2 of the Court of Claims Act and Article 17 of the Public Officers Law) define the scope of New York State's indemnification of its contractual counterparties.

9.4 If a Party is obligated to indemnify and hold the Indemnified Party harmless under this section, the amount owing to the Indemnified Party shall be the amount of such Indemnified Party's actual loss, as adjudicated by the Indemnifying Party's insurance carrier, net of any insurance or other recovery.

9.5 Promptly after receipt by an Indemnified Party of any claim or notice of the commencement of any action or administrative or legal proceeding or investigation as to which the indemnity provided for in this section may apply, the Indemnified Party shall notify the Indemnifying Party of such fact. Any unintentional failure of or delay in such notification shall not affect a Party's indemnification obligation unless such failure or delay is materially prejudicial to the Indemnifying Party.

X. CONSEQUENTIAL DAMAGES

10.1 Other than as expressly provided for in this Agreement or pursuant to the utility tariff, neither Party shall be liable to the other Party under any provision of this Agreement for any losses, damages, costs, or expenses for any special, indirect, incidental, consequential, or punitive damages, including but not limited to loss of profit or revenue, loss of the use of equipment, cost of capital, cost of temporary equipment or services, whether based in whole or in part in contract, in tort, including negligence, strict liability, or any other theory of liability; provided, however, that damages for which a Party may be liable to the other Party under another agreement will not be considered to be special, indirect, incidental, or consequential damages hereunder.

XI. MISCELLANEOUS PROVISIONS

11.1 Beneficiaries: This Agreement is intended solely for the benefit of the Parties hereto, and if a Party is an agent, its principal. Nothing in this Agreement shall be construed to create any duty to, or standard of care with reference to, or any liability to, any other person.

11.2 Severability: If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction, such portion or provision shall be deemed separate and independent, and the remainder of this Agreement shall remain in full force and effect.

11.3 Entire Agreement: This Agreement including standard clauses for a governmental contract (e.g. New York State Appendix A or State University of New York Exhibit A) constitutes the entire Agreement between the Parties and supersedes all prior agreements or understandings, whether verbal or written.

11.4 Waiver: No delay or omission in the exercise of any right under this Agreement shall impair any such right or shall be taken, construed or considered as a waiver or relinquishment thereof, but any such right may be exercised from time to time and as often as may be deemed expedient. In the event that any agreement or covenant herein shall be breached and thereafter waived, such waiver shall be limited to the particular breach so waived and shall not be deemed to waive any other breach hereunder.

11.5 Applicable Law: This Agreement shall be governed by and construed in accordance with the law of the State of New York.

11.6 Amendments: This Agreement shall not be amended unless the amendment is in writing and signed by the Utility and the Customer.

11.7 Force Majeure: For purposes of this Agreement, "Force Majeure Event" means any event: (a) that is beyond the reasonable control of the affected Party; and (b) that the affected Party is unable to prevent or provide against by exercising reasonable diligence, including the following events or circumstances, but only to the extent they satisfy the preceding requirements: acts of war, public disorder, insurrection, or rebellion; floods, hurricanes, earthquakes, lightning, storms, and other natural calamities; explosions or fires; strikes, work stoppages, or labor disputes; embargoes; and sabotage. If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, such Party will promptly notify the other Party in writing, and will keep the other Party informed on a continuing basis of the scope and duration of the Force Majeure Event. The affected Party will specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the affected Party is taking to mitigate the effects of the event on its performance. The affected Party will be entitled to suspend or modify its performance of obligations under this Agreement, other than the obligation to make payments then due or becoming due under this Agreement, but only to the extent that the effect of the Force Majeure Event cannot be mitigated by the use of reasonable efforts. The affected Party will use reasonable efforts to resume its performance as soon as possible.

11.8 Assignment to Corporate Party: At any time during the term, the Interconnection Customer may assign this Agreement to a corporation or other entity with limited liability, provided that the Interconnection Customer obtains the consent of the Utility. Such consent will not be withheld unless the Utility can demonstrate that the corporate entity is not reasonably capable of performing the obligations of the assigning Interconnection Customer under this Agreement.

11.9 Assignment to Individuals: At any time during the term, the Interconnection Customer may assign this Agreement to another person, other than a corporation or other entity with limited liability, provided that the assignee is the owner, lessee, or is otherwise responsible for the Unit.

11.10 Permits and Approvals: Interconnection Customer shall obtain all environmental and other permits lawfully required by governmental authorities prior to the construction and for the operation of the Unit during the term of this Agreement.

11.11 Limitation of Liability: Neither by inspection, if any, or non-rejection, nor in any other way, does the Utility give any warranty, express or implied, as to the adequacy, safety, or other characteristics of any structures, equipment, wires, appliances or devices owned, installed or maintained by the Interconnection Customer or leased by the Interconnection Customer from third parties, including without limitation the Unit and any structures, equipment, wires, appliances or devices appurtenant thereto.

ACCEPTED AND AGREED:

Interconnection Customer

Signature:

Printed Name:

Title:

Date:

Utility Signature:

Printed Name:

Title:

Date:

ATTACHMENT 1

ENERGY STORAGE SYSTEMS DESCRIPTION OF OPERATING PARAMETERS AND LIMITS

APPENDIX B -

NEW YORK STATE STANDARDIZED APPLICATION FOR INTERCONNECTION OF INVERTER BASED PARALLEL GENERATION EQUIPMENT TO THE ELECTRIC SYSTEM OF

Utility:

Customer:

Name: Phone: (   )

Address: Fax: (   )

Email:

Municipality:

Utility Account No.: Utility Meter No.:

Agent (if any):

Name: Phone: (   )

Address: Fax: (   )

Email:

Consulting Engineer or Contractor:

Name: Phone: (   )

Address: Fax: (   )

Email:

Existing Electric Service:

Capacity: _____ Amperes

Voltage: _____ Volts

Service Character: ( ) Single Phase ( ) Three Phase

Location of Protective Interface Equipment on Property:
(*Include address if different from customer address.*)

Energy Producing Inverter Information:

Total AC Nameplate Rating of All Inverters:

Inverter

Inverter or System Tested to UL 1741 (most current version):
( ) Yes ( ) No *If no, attach product literature.*

Manufacturer: Model:

Quantity:

Rating per inverter: _____ kW

Type: ( ) Forced Commutated ( ) Line Commutated
( ) Utility Interactive ( ) Stand Alone

Rated Output: _____ Amperes _____ Volts

Ramp Rate:

Method of Grounding: ( ) Grounded ( ) Ungrounded

Quantity of Inverters:

If there is more than one inverter of different types of manufacturers, please provide information on a separate sheet.

If applicable:

Step Up Transformer Winding Configuration:

( ) Wye-Wye ( ) Wye-Delta ( ) Delta-Wye

Other existing DG such as emergency generators, other renewable technologies, microturbines, hydro, fuel cells, battery storage, etc:

( ) Yes ( ) No

If yes, provide information about existing generation on separate sheet and include detail on single-line diagram.

Signature:

______________________________________ ____________________ ____________

CUSTOMER/AGENT SIGNATURE TITLE DATE

APPENDIX C -

NEW YORK STATE STANDARDIZED APPLICATION FOR INTERCONNECTION OF NON-INVERTER BASED PARALLEL GENERATION EQUIPMENT TO THE ELECTRIC SYSTEM OF

Utility:

Customer:

Name: Phone: ( )

Address: Fax: ( )

Email:

Municipality:

Utility Account No.: Utility Meter No.:

Agent (if any):

Name: Phone: ( )

Address: Fax: ( )

Email:

Consulting Engineer or Contractor:

Name: Phone: ( )

Address: Fax: ( )

Email:

Estimated In-Service Date:

Existing Electric Service:

Capacity: _____ Amperes

Voltage: _____ Volts

Service Character: ( ) Single Phase ( ) Three Phase

Secondary 3 Phase Transformer Connection: ( )Wye ( )Delta

Location of Protective Interface Equipment on Property:
(*Include address if different from customer address.*)

Energy Producing Generator Unit Information:

Manufacturer:

Model No.: Version No.:

( ) Synchronous ( ) Induction ( ) Other

Rating: _____ kW Rating: _____ kVA

Rated Output: _____ VA Rated Voltage: _____ Volts

Rated Frequency: _____ Hz Rated Speed: _____ RPM

Efficiency: _____ % Power Factor: _____ %

Rated Current: _____ Amps Locked Rotor Current: _____ Amps

Synchronous Speed: _____ RPM Winding Connection:

Min. Operating Freq./Time:

Generator Connection: ( ) Delta ( ) Wye ( ) Wye Grounded

Three-Line Diagram attached: ( ) Yes

Verification Test Plan attached: ( ) Yes

If applicable, Certification to UL 1741 attached: ( ) Yes

For Synchronous Machines:

Submit copies of the Saturation Curve and the Vee Curve

( ) Salient ( ) Non-Salient

Torque: ______ lb-ft Rated RPM:

Field Amperes: ______ at rated generator voltage and current

and _____ % PF over-excited

Type of Exciter:

Output Power of Exciter:

Type of Voltage Regulator:

Direct-axis Synchronous Reactance (X_d): _____ ohms

Direct-axis Transient Reactance (X'_d): _____ ohms

Direct-axis Sub-transient Reactance (X''_d): _____ ohms

For Induction Machines:

Rotor Resistance (R_r): _____ ohms Exciting Current: _____ Amps

Rotor Reactance (X_r): _____ ohms Reactive Power Required:

Magnetizing Reactance (X_m): _____ ohms, _____ VARs (No Load)

Stator Resistance (R_s): _____ ohms, _____ VARs (Full Load)

Stator Reactance (X_s): _____ ohms

Short Circuit Reactance (X''_d): _____ ohms,

Phases: ( ) Single Phase ( ) Three Phase

Frame Size: Design Letter:

Temp. Rise: _____ °C

Step Up Transformer Winding Configuration:
( ) Wye-Wye ( ) Wye-Delta ( ) Delta-Wye

Signature:

____________________ ____________________ ____________________

CUSTOMER/AGENT SIGNATURE TITLE DATE

APPENDIX D -

PRE-APPLICATION REPORT FOR THE CONNECTION OF PARALLEL GENERATION EQUIPMENT TO THE UTILITY DISTRIBUTION SYSTEM

Utility:

DG Project Information: (Provided to Utility by Applicant)
Customer name
Location of Project: (Address and/or GPS Coordinates)
DG technology type
DG fuel source / configuration
Proposed project size in kW (AC)
Date of Pre-Application Request
Pre-Application Report: (Provided to Applicant by Utility – 10 Business Days)
Date of Pre-Application Report Delivery
Operating voltage of closest distribution line
Phasing at site
Approximate distance to 3-Phase (if only 1 or 2 phases nearby)
Circuit capacity (MW)
Fault current availability, if readily obtained
Circuit peak load for the previous calendar year
Circuit minimum load for the previous calendar year
Approximate distance (miles) between serving substation and project site
Number of substation banks
Total substation bank capacity (MW)
Total substation peak load (MW)
Aggregate existing distributed generation on the circuit (kW)
Aggregate queued distributed generation on the circuit (kW)

APPENDIX E -

COST SHARING FOR SYSTEM MODIFICATIONS & COST RESPONSIBILITY FOR DEDICATED TRANSFORMER(S) AND OTHER SAFETY EQUIPMENT FOR NET METERED CUSTOMERS

Generator Type	Generator Size	Equipment Cost to **Residential** Net Metered Customers	Equipment Cost to **Non-Residential** Net Metered Customers****
Micro-CHP	Less than or equal to 10 kW	$350 maximum	N/A
Fuel Cell	Less than or equal to 10 kW	$350 maximum	As determined by Utility*
Fuel Cell****	Over 10 kW up to 2 MW	N/A	As determined by Utility*
Solar	Less than or equal to 25 kW	$350 maximum	$350 maximum
Solar****	Over 25 kW up to 2 MW	N/A	As determined by Utility*
Micro-hydroelectric	Less than or equal to 25 kW	$350 maximum	As determined by Utility*
Micro-hydroelectric****	Over 25 kW up to 2 MW	N/A	As determined by Utility*
Wind **	Less than or equal to 25 kW	$750 maximum	$750 maximum
Wind****	Over 25 kW up to 2 MW	N/A	As determined by Utility*
Farm Wind ***	Over 25 kW up to 500 kW	N/A	$5,000 maximum***
Farm Waste ***	Up to 2 MW	N/A	$5,000 maximum***

* Subject to review by the Commission at the request of the Customer. Such costs can include the total costs for upgrades to ensure the adequacy of the distribution system which would not have been necessary but for the interconnection of the net metered DG resource (as per PSL §66-l(3)(c)(iii)).

** Residential and Non-Residential Wind Customers with a total rated capacity up to 25 kW, Farm Wind may be required to also pay for feeder line upgrades that would not be required but for the interconnection of the net metered DG resource. Residential and Non-Residential Wind, and Farm Wind Customers are responsible for all feeder line upgrade costs if the total nameplate rating of the generating equipment exceeds 20% of the rated capacity of the feeder line (as per PSL §66-l(5)(c)(ii)). Farm Wind Customers are responsible for 50% of feeder line upgrade costs if the total nameplate rating of the generating equipment does not exceed 20% of the rated capacity of the feeder line (as per PSL §66-l(2)).

*** For Farm Wind projects with a total nameplate rating of the generation equipment that does not exceed 20% of the rated capacity of the local feeder line to which the project will connect, that portion of the CESIR costs related to transformers or other equipment installed at the customer's site is included in the $5,000 limitation; however, the customer is also responsible for 50% of the CESIR costs related to feeder line upgrades. Farm Wind projects with a total nameplate rating of the generation equipment that does exceed 20% of the rated capacity of the local feeder line to which the project will connect, CESIR costs related to transformers or other equipment installed at the customer's site is included in the $5,000 limitation; however, Farm Wind customers are responsible for the CESIR costs related to feeder line upgrades.

**** The first project triggering an eligible upgrade will initially bear 100% of the cost, while subsequent projects benefitting from those upgrades will reimburse the first project developer. The share of the costs paid by subsequent developers shall be calculated by the utility as the ratio of the total upgrade cost to the total AC watts the upgrade serves. If a third project uses the upgrade, the utility will perform a new calculation based on the new number of total watts served; the third project will pay its share and the utility will divide the third project's contribution among the first two projects. Sharing continues according to this formula until the capacity of the upgrade is used up or the net costs to the participating projects falls to $100,000 or lower, whichever comes first. The utilities shall administer the allocation process and track the payments among contributing projects. The utilities are authorized to collect a $750 fee from applicants for processing each reimbursement. The Equipment Upgrade Cost Sharing Requirement is limited in several ways. First, cost sharing only applies to substation 3V0 protection, substation transformer upgrades, and other substation-level shared upgrades. Second, only those upgrades that cost in excess of $250,000 are subject to sharing. Third, projects below 200 kW AC in size are not required to participate.

Cost Sharing for Qualifying Upgrades

The cost-sharing provisions herein apply to two categories of system modifications: Utility-Initiated Upgrades and Market-Initiated Upgrades, as defined below, both which utilize a pro rata approach whereby the applicant pays only for the specific distribution hosting capacity assigned to its project for these types of system modifications. A pro rata approach consists of taking the estimated cost of an upgrade and dividing that cost by the total increased Hosting Capacity created by the upgrade, thereby creating a dollar per kW cost which will then be multiplied by an individual project's AC nameplate rating in kW to determine the applicant's pro rata cost share. The rules specified in Section I. Application Process will continue to govern applicants' cost obligations with respect to all other system modifications.

1. Utility-Initiated Upgrades

The category of Utility-Initiated Upgrades consists of substation transformer bank (bank) installations or replacements and proactive zero sequence voltage (3V0) installations. Each utility shall identify its proposed Utility-Initiated Upgrades in its annual Capital Investment Plan (CIP). Each year, when the CIP is filed with the Commission, the utility will publish a link to the CIP on its system data portal and a list of those substations included in the CIP that are eligible for cost sharing hereunder as Utility-Initiated Upgrades where the utility plans to complete engineering within the next twenty-four (24) months. The utility will describe the scope of the upgrade to be performed at each such substation by providing planned design/construction schedules and funding estimates required to accommodate additional DG/ESS interconnections. After the established application deadline as defined below, the utility shall determine a pro rata cost per kW for the upgrade at each relevant substation.

A. Bank Upgrades (Proposed Multi-value Distribution Projects)

In the course of its planning process, at the time when the utility identifies the need to install or replace a bank due to asset condition, reliability, safety, resiliency, or capacity requirements, the utility shall consider options for designing the new bank equipment to create greater DG/ESS Hosting Capacity than the baseline installation would create. If the bank can be upgraded to increase Hosting Capacity while solving a pre-existing asset condition, reliability, safety, resiliency, or capacity issue, and if there is market interest that indicates DG/ESS growth above the capacity of the baseline equipment, the utility will identify the enhanced installation or replacement in the next published CIP as a Multi-value Distribution ("MVD") project. The utility will fund the cost of the baseline project. Participating Projects will fund the difference between the baseline and the MVD project cost.

If the utility determines, in its sole discretion, that there is sufficient time in the CIP project schedule (where "sufficient time" is baseline project specific and includes baseline projects where final design and engineering is not complete and prior to procurement) to allow additional DG/ESS developers to submit interconnection applications, the utility will publish a deadline for such applications on its system data portal with the link to the CIP. The utility notice will describe the baseline installation to be performed and the corresponding design/construction plan for the proposed baseline project. Within thirty (30) Business Days after the application deadline, the utility will calculate a cost per kW[1] for the upgrade for each project with an approved application to participate in the MVD Project Study and will provide that information and an invoice for MVD Project Study costs to each applicant. Applicants will have 10 Business Days to pay their share of the study costs; applicants who make this payment on time will be considered Participating Projects. Once Participating Projects commit to participate in the MVD Project Study, which requires the payment of their respective MVD Project Study cost share, Participating Projects will also be subject to CESIR payment timelines for project specific non-shared costs as per Section I-D. The utility will start the MVD Project Study and Participating Project CESIRs once the MVD Project Study and CESIR payments are received. If Participating Projects do not meet payment timelines and are withdrawn from queue, the pro rata cost per kW remains the same for remaining Participating Projects, and the Utility will have discretion on whether enough is collected to justify proceeding with the MVD project. The utility will have one hundred (100) Business Days to complete both the MVD Project Study and each Participating Project's CESIR.

The MVD Project Study result will include an indication of the incremental project equipment, Hosting Capacity enabled, preliminary milestone schedule, and revised cost per kW required to interconnect Participating Projects as part of the proposed MVD project. If the MVD Project Study indicates that the aggregate Participating Project capacity exceeds the capacity of the MVD project, the capacity will be assigned by interconnection queue position. After the MVD Project Study results are provided to the Participating Projects, for those Participating Projects where the MVD Study confirms available increased Hosting Capacity, a non-refundable full MVD Qualifying Upgrade payment for the shared costs of proceeding with the MVD project will be due within ninety (90) Business Days from each of the Participating Projects that want to proceed. If projects are withdrawn from the queue such that additional Participating Projects in queue can now benefit from Hosting Capacity created by the Qualifying Upgrade, the utility will send invoices to additional Participating Projects where the MVD project can now meet their Hosting Capacity needs. Applicants who receive an invoice under this provision shall pay the invoice within 30 Business Days or be withdrawn from the queue.

Based on the number of DG/ESS applicants that pay the non-refundable MVD Qualifying Upgrade payment and the CIP project schedule, the utility will have the discretion to move ahead with the MVD project. If the utility determines it will not proceed with the MVD project, it will provide notice of its decision and rationale to Participating Projects within fifteen (15) Business Days of receipt of the MVD Qualifying Upgrade payment and will refund those payments via the utility cost reconciliation process per Section 1-C. No MVD Qualifying Upgrade payments will be refunded to Participating Projects that are withdrawn from the queue after making such payments until/unless a subsequent project(s) take their place by making MVD Qualifying Payments that equal or exceed the MVD Qualifying Payments received from those withdrawing Participating Projects.

B. Proactive 3V0 Upgrades

The CIP will identify substations at which the utility plans to install 3V0 upgrades. Following the utility's filing of the CIP, additional applicants may apply for interconnection at the identified substations. The utility will accept applications at a substation designated for a 3V0 upgrade up to the maximum capacity available at the site for reliable and safe operation. The utility will have the discretion to proceed where 3V0 upgrades are feasible. Payments will be due in accordance with CESIR payment timelines as per Section 1-D.

2. Market-Initiated Upgrades

This section addresses cost-sharing for Qualifying Upgrades identified in the course of the interconnection application process.

A. Process for Market-Initiated Upgrades

Whenever the utility determines that a substation Qualifying Upgrade is required to interconnect a Triggering Project, the utility will promptly discuss its finding with the applicant. If the applicant decides to continue with the application, then in addition to the CESIR process outlined in Section I-C, the utility will proceed with a more detailed study to develop a cost estimate and initial construction schedule for the Qualifying Upgrade. The utility will determine the Qualifying Upgrade Cost and the net increase in Hosting Capacity that would result from the construction of that modification. The utility shall have up to forty (40) Business Days to conduct the additional study to assess the Qualifying Upgrade and complete the CESIR. The utility will present the Qualifying Upgrade use case and supporting details in the Qualifying Upgrade Disclosure, which will include the following items:

1. The technology option(s) considered to address the electric system impacts;
2. The Qualifying Upgrade selected by the utility;
3. The estimated Qualifying Upgrade Cost and increase in Hosting Capacity;
4. The estimated Capacity Increase Shared Cost (per kW AC); and
5. A Preliminary Milestone schedule for the Qualifying Upgrade.

The utility will also publish the Qualifying Upgrade Disclosure with the next monthly update to the utility's system data portal after the CESIR is delivered to the Triggering Project applicant.

The CESIR will assign the Triggering Project and any Sharing Project its Qualifying Upgrade Charge. In accordance with the requirements of Section 1-D, each applicant shall pay 25% of the project specific costs ninety (90) Business Days following the CESIR delivery and pay 75% of the project specific costs and Qualifying Upgrade Charge one hundred and twenty (120) Business Days from when the utility confirms receipt of the 25%. No Qualifying Upgrade Charge payments will be refunded to Participating Projects that are withdrawn from the queue after making such payments until/unless a subsequent project(s) take their place by making Qualifying Upgrade Charge payments that equal or exceed the Qualifying Upgrade Charge payments made by the withdrawing Participating Projects.

For Qualifying Upgrades that are distribution/sub-transmission line and underground secondary network upgrades,[2] the utility shall charge the Triggering Project the full cost estimate for the Qualifying Upgrade as established in the CESIR. In accordance with the requirements of Section I-D, Triggering Project and Sharing Project(s) shall make 25% and 75% payments. The 25% payment is refundable until the project makes the 75% payment, at which time both payments become non-refundable. At the time the Triggering Project applicant makes its first payment, the utility shall designate the upgrade as a "DG/ESS Encumbered Line." Construction of the upgrade shall begin once the utility has received full payment of the cost estimate. Any Sharing Project(s) above 50 kW AC that later proceeds to CESIR will be charged its pro rata share of the Qualifying Upgrade. The utility will calculate the pro rata share based on the capacity of the DG/ESS project and footage used. After five years from the first project interconnection, or when the Triggering Project's contribution after reimbursement becomes less than $100,000, whichever occurs first, the line will no longer be considered a "DG/ESS Encumbered Line." No payments shall be refunded to a Sharing Project(s) after making full payment until a subsequent project(s) takes their place by making their full payment. At the discretion of the applicant, the Triggering Project can opt out of cost sharing until the 75% payment date, thereby classifying the upgrade as a project specific non-shared upgrade and be subject to the rules for project specific non-shared costs as per Section I-D.

B.Project Profiles to Be Considered in Site Selection and Eligible for the Market-Initiated DG/ESS Upgrade Mechanism

Participating Projects must be greater than 50 kW AC nameplate rating in size, or Participating Projects proposed by the same developer, within a six-month period, must be greater than 50 kW AC nameplate rating in aggregate.

The table below, "Market-Initiated Cost Sharing 2.0 Mechanisms", provides a breakdown of Triggering and Sharing project cost responsibilities, Mobilization Threshold, and Refundability/Reconciliation of the various Market-Initiated Qualifying Upgrade mechanisms.

Market-Initiated Cost Sharing 2.0 Mechanisms

Market-Initiated Qualifying Upgrade	CESIR Cost Responsibility		Mobilization Threshold	Refundability and Reconciliation
	Triggering Project	Sharing Project		
Distribution and Sub-Transmission Lines and Underground Secondary Network Upgrades	100% of Qualifying Upgrade Cost	Pro-Rata Share based on kW Capacity and Footage	Upon payment of 100% of Qualifying Upgrade Cost by Triggering Project	The 25% payment is refundable until the project makes the 75% payment at which time both payments become non-refundable. Qualifying Upgrade Costs are non-refundable for the Triggering Project until a Sharing Project provides payment such that the utility has receipt of 100% of Qualifying Upgrade Cost. Upon receipt of additional payments by Sharing Projects the utility shall reconcile with the Triggering Project based on a calculated estimated pro-rata share. Remaining reconciliation for Qualifying Upgrade Cost to occur pursuant to Section I-C of the SIR.
Transformer Bank	Pro-Rata Share of Qualifying Upgrade Cost based on kW Capacity	Pro-Rata Share of Qualifying Upgrade Cost based on kW Capacity	Upon payment of 75% of Qualifying Upgrade Cost by Triggering Project and Sharing Project(s)	Qualifying Upgrade Costs are non-refundable until another Sharing Project provides payment such that the utility has received payments equal to the pro-rata share of the Qualifying Upgrade. Remaining reconciliation for Qualifying Upgrade Cost to occur pursuant to Section I-C of the SIR.
Other Qualifying Substation Upgrades	Pro-Rata Share of Qualifying Upgrade Cost based on kW Capacity	Pro-Rata Share of Qualifying Upgrade Cost based on kW Capacity	Upon payment of 25% of Qualifying Upgrade Cost by Triggering Project and Sharing Project(s)	Qualifying Upgrade Costs are non-refundable until another Sharing Project provides payment such that the utility has received payments equal to the pro-rata share of the Qualifying Upgrade. Remaining reconciliation for Qualifying Upgrade Costs to occur pursuant to Section I-C of the SIR.

C. Utility Mobilization Thresholds

The utility shall proceed to construct a Qualifying Upgrade, other than a distribution/sub-transmission line upgrade or underground secondary network upgrade, once it has collected sufficient funds from the Triggering and Sharing Project(s) in accordance with the following:

1. For all substation upgrades other than a transformer installation/upgrade, the utility shall proceed once Participating Project payments total at least 25% of the estimated Qualifying Upgrade Cost.
2. For a substation transformer installation/upgrade and associated work, construction shall begin once payments made by Participating Projects equal at least 75% of the estimated Qualifying Upgrade Cost. If the 75% threshold is not collected within twelve (12) months of an applicant paying its full construction contribution, then the applicant may request a refund, which the utility shall process within sixty (60) Business Days of the request.
3. If Triggering Project and Sharing Project(s) Hosting Capacity needs are below the minimum subscription threshold, the Triggering Project, or the Triggering Project and any Sharing Project(s), may agree to fund shares beyond their capacity needs so that the minimum subscription threshold criterion is met.
4. To mitigate the risk to utility customers, unrecovered costs shall be capped at 2% of a utility's distribution/sub-transmission electric capital investment budget per fiscal year, after which any Qualifying Upgrades would require full (100%) funding from Triggering Projects and Sharing Projects prior to utility mobilization for such projects' construction work.

3. Capital Project Queues

The utility will create a Capital Project Queue at the substation or feeder level for each Utility-Initiated Upgrade and Market-Initiated Upgrade identified under these rules where utility construction will take longer than twenty-four (24) months. The utility will note on its Hosting Capacity map that the station/feeder is impacted by the Capital Project Queue due to future work.

Applications pending at the time a Capital Project Queue is created will be placed into the queue if the applicant consents. New applications will be placed into a Capital Project Queue following the Preliminary Screening Analysis. The payment timelines in Section 1-D will be suspended for applications assigned to a Capital Project Queue, except as provided otherwise in this Section.

When the upgrade for a given substation is within eighteen (18) months of the expected completion date, applications will be removed from in the Capital Project Queue and will advance through the remaining SIR steps based on their original application completion date. Any project that was placed in the Capital Project Queue after the CESIR was complete will need to go through the CESIR process again due to potential changes to the utility's electric power system, unless the utility determines that a restudy is not needed.

4. Unsubscribed Capacity

Utilities will continue to collect contributions from Participating Projects up to five (5) years after a Qualifying Upgrade is placed in service, or all available Hosting Capacity from a Qualifying Upgrade is used, whichever occurs first.

If the Triggering Project and initial Sharing Project(s) have met the minimum threshold to begin the upgrade, but the available Hosting Capacity has not been completely filled and thus utility customers contribute to the unassigned costs (either through the establishment of a deferred regulatory asset or in base rates), then any additional Sharing Projects that use available Hosting Capacity up to five (5) years after the upgraded asset is placed in service will be required to fund their pro rata share prior to interconnection, and utility customers shall receive the benefit provided by those additional Sharing Project(s). At the time additional Sharing Project(s) provide contributions for Qualifying Upgrades under this scenario, the following utility customer protections shall apply:

i. For Qualifying Upgrades that are in service but NOT included in base rates, the utility shall cease deferring the return on, and return of, investment associated with contributions from subsequent Sharing Projects. Additionally, the Qualifying Upgrade is to be excluded from the utility's net plant, or capital expenditure, tracking mechanism until it is included in base rates.

ii. For Qualifying Upgrades that are in service AND included in base rates, the utility is required to reduce plant in service by the funds provided by additional Sharing Project(s). The utility's net plant, or capital expenditure, tracking mechanism will provide utility customers with the benefit of funds received from the additional Sharing Project(s).

If the additional Hosting Capacity needs of the Triggering Project and initial Sharing Project(s) are below the minimum subscription threshold, and the Triggering Project and initial Sharing Project(s) (if any), agree to fund shares beyond their capacity needs so that the minimum subscription threshold criterion is met, then the Triggering Project and initial Sharing Project(s) have provided contributions in excess of the Capacity Increase Shared Cost rate multiplied by their respective Hosting Capacity. Under this scenario the cost of unsubscribed capacity is being borne by the Triggering Project, previously paid Sharing Project(s) (if any), and utility customers.

Additional Sharing Projects that connect to the upgraded station/feeder will be required to contribute such that the Triggering Project, initial Sharing Project(s) (if any), and additional Sharing Projects have provided funding at an equal dollar per kW of Hosting Capacity. Triggering Projects and previously paid Participating Projects are to be provided refunds (from the utility) as a result of the additional contribution of Sharing Project(s). Refunds shall be provided to the Triggering Project and previously paid Sharing Project(s) until the Participating Projects have provided funding at a level that is equivalent to their Capacity Increase Shared Cost multiplied by their respective Hosting Capacity level. If additional Sharing Projects provide funding, the utility customer protections described in Scenario 1 (sections i and ii) shall apply.

5. Cost Reimbursement

The Utility will reimburse Participating Projects for the costs of Qualifying Upgrades in advance of the final project cost reconciliation process established in section 1.C, Step 11 of the SIR, as provided in this section. These reimbursements will be based on the cost estimates provided by the utility.

For upgrades involving the DG Encumbered Line mechanism, Triggering Projects and previously paid Sharing Projects shall be reimbursed by the utility when later Sharing Projects make their full payments, with contributions to be calculated based on project size and footage utilized. Once the Triggering Project and Sharing Project(s) have paid 100% of their respective payments, the utility will reimburse Sharing Projects' estimated costs to the Triggering Project within sixty (60) Business Days. When the final utility costs for all participating projects on a DG Encumbered Line are known, both the Triggering Project and any Sharing Projects will be billed or refunded by the utility as provided in the SIR.

When any Triggering Project or Sharing Projects pay more than their pro rate cost shares in order to reach a mobilization threshold, as provided in section D.3 above, payments from additional Sharing Projects received after the mobilization threshold is reached will be first applied to the Triggering Project and initial Sharing Project(s) that paid more than their pro rata cost share, until the Triggering Project and Sharing Projects' contributions are equal to the pro rata share of each project based on capacity needs. When the final costs are known, the Triggering Project and Sharing Projects will be billed or refunded based on the actual costs per the SIR. Applications held in the interim queues pursuant to the Commission's March 21, 2021 Order Directing Interim Modifications to the New York State Standardized Interconnection Requirements that pay the full cost of a Qualifying Upgrade shall treated as Triggering Projects and shall be reimbursed in accordance with the rules stated in the preceding paragraph.

APPENDIX F -

APPLICATION PACKAGE CHECKLIST

Completed standard application form	√
New York State Standardized Acknowledgement of Property Owner Consent Form – For Systems above 50 kW up to 5 MW Only – Refer to Appendix H for form	√
For residential systems rated 50 kW and below, a signed copy of the standard contract	√
Letter of authorization, signed by the Customer, to provide for the contractor to act as the customer's agent, if necessary	√
If requesting a new service, a site plan drawing with the proposed interconnection point identified by a Google Earth, Bing Maps, or similar satellite image. The drawings shall show all electrical components proposed for the installation and their connections to the existing on-site electrical system from that point to the PCC, and shall be clearly marked to distinguish between new and existing equipment. For those projects on existing services, account and meter numbers shall be provided.	√
Description / Narrative of the project and site proposed. If multiple DG systems are being proposed at the same site/location, this information needs to be identified and explained in detail.	√
DG technology type	√
DG fuel source / configuration	√
Proposed project size in AC kW	√
Project is net metered, remote, or community net metered	√
Copy of the certificate of compliance referencing UL 1741. If proposing power-limited equipment, provide additional generic letter by manufacturer detailing output range in which inverter model(s) were tested and certified to UL 1741.	√
Copy of the manufacturer's product data sheet for the interface equipment. For custom equipment *(e.g.*, transformer, disconnect, or recloser), copy of the manufacturer's product brochure.	√

For systems 50 kW or less, provide a copy of manufacturer's verification test procedures.	√
For solar PV and BESS applications – a single-line drawing that meets the requirements of this Appendix. For all other types of applications – a three-line diagram that meets the requirements of this Appendix. Single-line and three-line diagrams must include the following: 1. Number, individual ratings, connection configurations, and type of all major electrical components such as generating units, step-up transformers, auxiliary transformers, grounding transformers, neutral reactors, and switches/disconnects of the proposed interconnection, including the required protection devices (instrument transformer configuration and polarity if applicable) and circuit breakers. 2. Proposed inverter protection settings (and relay equipment settings if applicable). 3. Proposed generator step-up transformer MVA ratings, impedances, tap settings, neutral connections, winding configurations, and voltage ratings. 4. For those systems proposed to be interconnected at a system voltage of 1,000 volts or greater, the drawings shall be sealed by a NYS licensed Professional Engineer. 5. Control system designs, phase sequencing, differential relay settings, ground connections, and metering transformer connections.	√

APPENDIX G -

APPLICATION SCREENING

PRELIMINARY SCREENING

All Preliminary Screens shall be completed by the utility and results shall be provided to the applicant in accordance with Section C, Step 4.

Screen A: Is the PCC on a Networked Secondary System?

Does the proposed system connect to a secondary network system?

- Yes (Proceed to Screen B, then complete Screens 1 through 3)
- No (Proceed to Screen B, then complete Screens C through F)

Screen B: Is Certified Equipment Used?

Does the applicant propose to use equipment that has been listed to meet UL 1741 (Inverters, Converters and Charge Controllers for Use in Independent Power Systems) and for inverter-based equipment, UL 1741, including supplement B (UL 1741 SB), with settings as specified in the utility's technical requirements document, by a nationally recognized testing laboratory?

- Yes (Pass Screen)
- No (Fail Screen)

Screen 1: Are the existing service, transformer, and network protector(s) adequate?

- Yes (Pass Screen)
- No (Fail Screen)

Are the existing service, transformer (*i.e.*, transformer closest to PCC), and network protector(s) adequate to interconnect the aggregate and proposed DER capacity (inclusive of this proposed project)?

- Yes (Pass Screen)
- No (Fail Screen)

Screen 2: Is the proposed DG system compatible with the utility grid?

2(a) Identify the equipment type (inverter, synchronous, induction, or hybrid) and capacity (kW).

2(b) Can the network protector(s) accommodate reverse power?

- If answer to Items 2(a) and 2(b) Pass (Pass Screen)
- If answer to Item 2(a) or 2(b) Fails (Fail Screen)

Screen 3: Simplified Penetration Test

3(a) Is the aggregate interconnected and proposed DER capacity (including this proposed project) less than 15% of the minimum load of the network?

3(b) Is the sum of the aggregate interconnected and proposed DER capacity (inclusive of this proposed project) in the local network less than 50% of the minimum load on the transformer(s) in this area?

- If answer to Items 3(a) and 3(b) is Yes (Pass Screen)
- If answer to Item 3(a) or 3(b) is No (Fail Screen)

Screen C: Is the Electric Power System (EPS) Rating Exceeded?

Does the maximum aggregated generation or loading capacity connected to an EPS (existing and approved prior to application) exceed any EPS ratings (modified per established utility practice)?

- Yes (Fail Screen)
- No (Pass Screen)

Screen D: Is the Line and Grounding Configuration Compatible with the Interconnection Type?

1. Identify primary distribution line configuration that will serve the distributed generation or energy storage. Based on the DER interconnection and using the table below, determine compatibility with the electric power service, including, phase balance, line and grounding configuration. The following table shall be used to determine risk for ineffective grounding

Primary distribution line configuration	**Type of DER connection to primary**	**Result/Criteria**
Three-phase, three-wire	Any type	Pass
Three-phase, four-wire > 5 kV	Single-phase line-to-neutral	Pass
All Three-phase, four-wire (For any line that has sections or mixed three-wire and four-wire)	All others	Fail. To pass aggregate DER AC nameplate rating must be less than or equal to 10% of line-section peak load

2. Based on aggregate DER on the feeder, is phase balancing maintained within utility limits?
   - If items 1 & 2 pass, (Pass Screen)
   - If items 1 or 2 fail, (Fail Screen)

Screen E: Simplified Penetration Test

If the aggregate DER capacity on any medium voltage line section (existing and approved prior to application) is less than the daytime minimum load (where 12 months of line section minimum load data are available or alternatively can be estimated from existing data, or determined from a power flow model) or 15% of the annual peak load (where daytime minimum load data is not available) for all line sections bounded by automatic sectionalizing devices upstream of the DER?

- Yes (Pass Screen)
- No (Fail Screen)

Screen F: Is Feeder Capacity Adequate for Individual and Aggregate DER?

1. Is the feeder available short circuit capacity at the medium voltage PCC, divided by the rating of the individual DER, greater than 25?
2. Is the feeder available short circuit capacity at the substation divided by the capacity all aggregate DER on the feeder, greater than 25?
   - If items 1 & 2 pass, (Pass Screen)
   - If items 1 or 2 fail, (Fail Screen)

SUPPLEMENTAL SCREENING ANALYSIS

All Supplemental Screens (G-I) shall be completed by the utility and results shall be provided to the applicant in accordance with Section C, Step 4.

Screen G: Reverse Power Flow Test

Where the aggregate DER capacity exceeds the minimum load for all line sections bounded by upstream equipment, does the EPS have the capability to support reverse power flow?

- Yes (Pass Screen)
- No (Fail Screen)

Screen H: Voltage Flicker Test

Can it be determined that the voltage fluctuation is within acceptable limits as defined by IEEE 1453?

1. Voltage flicker emission generated by each fluctuating installation (Pst) should be calculated using the following formula:

$$\Delta V = (d/d_{Pst=1}) \times F \leq 0.35 \quad \text{and} \quad d = ((RL \times \Delta P + XL \times \Delta Q) / V^2)$$

<u>When</u>: X_L/RL < 5

<u>OR</u>

$$\Delta V = (d/d_{Pst=1}) \times F \leq 0.35 \quad \text{and} \quad d = (\Delta V/V) \approx (\Delta S/S)$$

<u>When</u>: $X_L/RL \geq 5$

<u>Whereby</u>:

PV Plant Variability = $(F/d_{Pst=1})$ = 0.2/2.56% = 7.8

Explanation of Variables & Acronyms
d *= the relative voltage change caused by the DER at the PCC*
dpst *= 1 (curve value) is the relative voltage change that yields a Pst value of unity when voltage fluctuations are rectangular*
Pst *= the short-term flicker emission limit for the customer installation (typically based on 10-minute time frame)*
X_L *= the line reactance in ohms*
R_L *= the line resistance in ohms*
Isc *= the maximum available 3-phase fault current at the PCC in amperes*
Ssc *= the maximum available fault apparent power at the PCC*
ΔS *= the change in apparent power in volt amperes* ***ΔP***
= the change in real power in watts of the DG ***ΔQ*** *=*
the change in reactive power in vars of the DG ***V*** *= the*
nominal line to line voltage
ΔV *= the change in voltage at the PCC*
F *= the shape factor related to the shape of the expected voltage fluctuation*

2. Can it be determined within the Supplemental Review that aggregate DER does not cause voltage excursion outside of ANSI C84.1 Range A?
3. Can it be determined that an aggregate DER generation change of 75% of nameplate does not result in a voltage change of greater than half the bandwidth of any voltage regulating device on the associated feeder?

A Pst greater than 0.35 as calculated in Step 1 or no to the determination in Steps 2 and 3 constitutes failure of this screen.

Screen I: Operating Limits, Protection Adequacy and Coordination Evaluation

1. Review anti-islanding protection requirements based on the most recent version of the JU Unintentional Islanding Protection Practice and identify utility and DER system upgrades, if required.
2. Review DER system configuration to determine if design and operation meets utility's effective grounding and ground source contribution requirements.
3. Identify equipment where fault current exceeds 90% of its short circuit current interrupting capability.
4. Identify any additional concerns related to utility and DER protection adequacy and protection, including but not limited to: protective device coordination and coverage, load rejection overvoltage, and 3V0 protection (where applicable).

APPENDIX H -

New York State Standardized Acknowledgment of Property Owner Consent Form

Interconnecting Utility: ___________________________
Utility Project Number (if available): ___________________________________

(Note: This Acknowledgment is to be signed by the owner of the property where the proposed distributed generation facility and interconnection will be placed, when the owner or operator of the proposed distributed generation facility is not also the owner of the property, and the property owner's electric facilities will not be involved in the interconnection of the distributed generation facility.)

This Acknowledgment is executed by ____, (the "Property Owner"; as used herein the term shall include the Property Owner's successors in interest to the Property), as owner of the real property situated in the City/Town of ____________________, ___________County, New York, known as ____________________________ [street address] (the "Property"), at the request of ____________________________________ [name of Developer] (the "Developer"; as used herein the term shall include the Developer's successors and assigns).

This Acknowledgment does not grant or convey any interest in the Property to the Developer.

1. The Property Owner certifies as of the date indicated below that the Property Owner is working exclusively with the Developer on a proposal to install a distributed generation facility (the "Facility") on the Property.

   OR

2. The Property Owner certifies as of the date indicated below that the Developer has executed with the Property Owner one of the following: a signed option agreement to lease or purchase the Property, an executed Property lease, or an executed purchase agreement for the Property granting the Developer a right to use the Property for purposes of installing the Facility.

Property Owner:	Developer:
By: _______________________________	By: _______________________________
Name: _____________________________	Name: _____________________________
Title: _____________________________	Title: _____________________________
Date: _____________________________	Date: _____________________________

APPENDIX I -
New York State Standard Moratorium Attestation Form

[UTILITY COMPANY NAME]
[UTILITY DEPT. NAME AND CONTACT NAME]
[UTILITY STREET ADDRESS]
[CITY/TOWN, New York [ZIP CODE]

<table>
<tr><td rowspan="6">Re:</td><td rowspan="2">DEVELOPER</td><td>[name]</td></tr>
<tr><td>[contact information]</td></tr>
<tr><td>PROJECT</td><td>[utility ID number]</td></tr>
<tr><td rowspan="3">PROPERTY</td><td>[street address]</td></tr>
<tr><td>[municipality/county]</td></tr>
<tr><td>[city/town and zip code]</td></tr>
</table>

________________________ [DEVELOPER NAME] hereby attests that it will notify the interconnecting utility identified above of the date that the moratorium on solar development in ________________________ [MUNICIPALITY NAME] is lifted.

By signing below, Developer confirms that this attestation is true and correct.

By: ________________________________

Printed Name: ______________________

Title: _____________________________

APPENDIX J -
New York State Standard Site Control Certification Form

[UTILITY COMPANY NAME]
[UTILITY DEPT. NAME AND CONTACT NAME]
[UTILITY STREET ADDRESS]
[CITY/TOWN], New York [ZIP CODE]

Re:	DEVELOPER	[name]
		[contact information]
	PROJECT	[utility ID number]
	PROPERTY	[street address]
		[municipality/county]
		[city/town and zip code]

___________________________________(the "Property Owner") is the owner of the above- referenced property (the "Property").
________________________________(the "Developer") is the developer of the project identified above.

The Property Owner and the Developer have entered into an agreement authorizing the Developer to use the Property for the purpose of constructing and operating a distributed generation facility. The type of agreement that is in place is indicated below by a check mark.

	Signed option agreement to lease or purchase the Property
	Executed lease agreement for the Property
	Executed agreement to purchase the Property
	License or other agreement granting exclusive right to use the Property for purposes of constructing and operating the distributed generation facility

Property Owner and Developer entered into the agreement on or about _______________
(MM/DD/YYYY)

Terms of Agreement (including options to extend) _______________
(MM/DD/YYYY)

Property Owner

By: ______________________________

Printed Name: _____________________

Title: ______________________________

Date: ______________________________

Developer

By: ______________________________

Printed Name: _____________________

Title: ______________________________

Date: ______________________________

APPENDIX K -

Energy Storage System (ESS) Application Requirements / System Operating Characteristics / Market Participation

Application Requirements

a. Provide a general overview / description and associated scope of work for the proposed project. Is the new ESS project associated with a new or existing DG facility? (if information is available.) Use the example given below for the project description if information is available.

Project consists of a new **AC-coupled hybrid** Distributed Generator (DG) and Energy Storage System (ESS). The proposed project is not associated with any other existing DER at the facility OR The proposed project is associated with project XYZ (provide project number from relevant utility's IOAP). The DG consists of a **2000 kW / 2000 kVA** solar PV system, and the ESS will be a single inverter **979.2 kW / 1000 kVA** with a **3916.8 kWh** rating. The required ESS charging capacity of our system will be **4189 kWh** factoring in round trip efficiency of **93.5%** and will charge from both the PV and the grid. The system will have an auxiliary load of **45 kVA**, and the itemized list will be included in the line diagram.

b. Identify whether this is a Stand-Alone or Hybrid ESS proposal, or a change to the operating characteristics of an existing system. If Hybrid ESS, please select the configuration option:

1. Hybrid Option A - ESS is charged exclusively by the DG

2. Hybrid Option B - ESS will not export to the grid, only DG will.

a. Hybrid Option C - ESS may charge/discharge unrestricted from the grid, but grid consumption by ESS is netted out of grid exports.[1]

3. Hybrid Option D - ESS may charge/discharge unrestricted from the grid, but any consumption on the account is netted out of grid exports

4. N/A - not Value Stack

[1] ESS may have restricted charge/discharge to be defined in Question 2e.

c. Market participation:[2]

1. Compensated under a utility tariff(s)? If yes, please specify. Identify any associated use case stacking (*i.e*., parallel standby, net meter, VDER, import only, export only, peak shaving, generator firming, demand response, etc.) if applicable.
2. NYISO markets? If yes, has the NYISO process been initiated? Please specify which anticipated NYISO market(s).
3. As part of an NWA? If yes, please specify which associated NWA.
4. program or market not listed? If yes, please describe.

d. Indicate DER system nameplate rating based on the proposed project configuration, i.e., stand-alone, AC-coupled or DC-coupled. The values should be broken down by existing DER and DER to be in stalled in the DER Nameplate Rating table below. Also indicate the total exporting capacity and total importing capacity including all losses in the Storage Capacity Table.

Table 1. DER Nameplate Rating

DER System		**Inverter Nameplate Rating**		**Factory Limited Nameplate Rating***	
		kW	**kVA**	**kW**	**kVA**
Stand-Alone	New Storage to be Installed				
	Existing Storage Installation if Applicable				
AC-Coupled System	New Storage to be Installed				
	Existing Storage Installation if Applicable				
	New DG to be Installed				
	Existing DG Installation if Applicable				
DC-Coupled System	New Storage and DG to be Installed				
	Existing DG and Storage Installation if Applicable				

* If the factory nameplate rating reflects system limitations, the equipment manufacturer shall additionally provide a letter verifying the factory limited reduced rating of the system before the utility can utilize the factory limited nameplate rating in the CESIR.

[2] Market participation information is non-binding but may be used to verify operating characteristics and metering configuration. Participation in NYISO markets and NWA programs may influence the technical study.

Table 2. Storage Capacity

Storage Capacity in kWh	
Total Export Capacity	
Total Import Capacity - Charging and Losses	
Round Trip Efficiency	

e. Provide specification data/rating sheets for both the AC and/or DC components including the manufacturer, model, and nameplate ratings (kW) of the inverter(s)/converters(s) and controllers for the ESS and/or DG system, and capacity of ESS unit(s) (kWh).

f. Indicate the type of Energy Storage (ES) technology to be used. For example, NaS, Dry Cell, PB-acid, Li-ion, vanadium flow, etc.

g. Will the proposed project provide both real power and reactive power (PQ injection)?

h. Will the proposed project provide reactive power control, either via volt/VAR mode or specific power factor?

i. Indicate whether the interconnected inverters inverter(s)/converter(s) is/are compliant to the latest versions of the following additional standards. If partially compliant to subsections of the latest standards, please list those subsections:

   1. IEEE 1547a - 2018
   2. UL 1741, including supplement B (UL 1741 SB), with settings as specified in the utility's technical requirements document
   3. List the UL 1741 CRD for PCS, if this applies to the project. Also mention the certification tests that were performed and/or excluded for the proposed inverter.
   4. List the UL 1741 CRD for Multimode, if this applies to the project. Also mention the certification tests that were performed for the proposed inverter.

j. List the system's maximum import in kW AC, including any equipment and ancillary loads (*i.e.*, HVAC) to be installed to facilitate the ESS installation.

   List the ancillary equipment's maximum import in kW and kVA for HVAC and other aggregated ancillary loads in the table below. Where data on ancillary equipment load is unavailable, please provide the best estimate.

Table 3. List of Ancillary Equipment and Load

Ancillary Equipment	Ancillary Load	
	kW	kVA

k. Indicate desired ramp rates in kW/second during charging and discharging (worst case will be assumed if not provided). Please attach a charge and discharge data/curve.

l. Is the ESS symmetrical or asymmetrical (*e.g.*, charge magnitude equivalent to discharge magnitude)? Provide proposed inverter(s) power factor operating range and anticipated operational setpoints[63][3] in the context of the expected two-quadrant or four-quadrant operation.

m. Indicate the maximum potential change in power magnitude expressed in equipment limitations such as per-second, minute, hour, or day, and kW or % of kW as applicable.

n. Add check boxes against the preferred charging and discharging windows in Table 5 below. For a 24/7 unrestricted schedule, check all boxes for charging and discharging windows. Where scheduled operation is selected, please ensure that the energy storage system's operation is aligned with the local utility's guidelines for charging and discharging. Be advised that the specific conditions and requirements of the local electrical circuit will be the determining factor for the final operational charge/discharge windows and rates. If not specified, the utility will prescribe operational windows based on the local utility's guidelines for scheduled operation. Also indicate any specific operational limitations that will be imposed (e.g., will not charge or discharge across PCC between 2-7 pm; etc.).

Please indicate if the project should be studied for one or both scenarios.

Table 4. Preferred Study Operation Windows

Study Operation Windows	**Yes/No**
Preferred/selected operation window	
24/7 unrestricted operation	

If 24/7 unrestricted operation is not selected, please fill the table below. In the Capacity (kW) column, mention the fraction of battery nameplate capacity in whole numbers that will charge or discharge.

[63] Final setpoints are subject to change per utility's direction.

Table 5. 24/7 Charging and Discharging Schedule

Time of operation	Charging		Discharging	
	Check as applicable	**Capacity (kW)**	**Check as applicable**	**Capacity (kW)**
2400-0100	□		□	
0100-0200	□		□	
0200-0300	□		□	
0300-0400	□		□	
0400-0500	□		□	
0500-0600	□		□	
0600-0700	□		□	
0700-0800	□		□	
0800-0900	□		□	
0900-1000	□		□	
1000-1100	□		□	
1100-1200	□		□	
1200-1300	□		□	
1300-1400	□		□	
1400-1500	□		□	
1500-1600	□		□	
1600-1700	□		□	
1700-1800	□		□	
1800-1900	□		□	
1900-2000	□		□	
2000-2100	□		□	
2100-2200	□		□	
2200-2300	□		□	

2300-2400	☐		☐	

o. Provide a summary of protection and control scheme functionality and provide details of any integrated protection of control schematics and default settings within controllers.

p. Submit control schemes, electrical configurations, and sufficient details for the utility to review and confirm acceptance of proposal. Detail any integrated control scheme(s) that are included in the interconnected inverter(s)/converters including a sequence of operations for expected events, energy flows, or power restrictions. For example, provide details if the ESS can be charged only through the DG input, or if the ESS can be switched to be charged from the line input, or if a control scheme is proposed to prohibit power flow directionality or peak values. Provide details on grounding of the interconnected ESS and/or DG system to meet utility's effective grounding requirements.

q. Provide short circuit current capabilities and harmonic output from the hybrid ESS project or stand-alone ESS.

r. If the intended use case for the ESS includes behind-the-meter backup services, please provide a description and documentation illustrating how the entire system disconnects from the utility during an outage (*e.g.*, mechanical or electronic, coordination, etc.).

Optional Questions

Questions in this section are not required for a complete application, although any responses provided may support the utility's decision to review the project performance in a manner that could result in less impact to the customer interconnection.

a. Indicate whether the interconnected inverters inverter(s)/converter(s) is/are compliant to the latest versions of the following additional standards. If partially compliant to subsections of the latest standards, please list those subsections:
    a. SunSpec Common Smart Inverter Profile (CSIP) v2.103-15-2018

b. Any other recognized standard or practice. Indicate the maximum frequency of change in operating modes (*i.e.*, charging to discharging and vice-versa) that will be allowed based upon control system configurations.

c. Provide details on standard communication as follows:

    a. Hardware interfaces that are available, *e.g.*, TCP/IP, serial, etc.

    b. Protocols that are available, *e.g.*, MODBUS, DNP-3, 2030.5, etc.

    c. Data models that are available, *e.g.*, 61850-90-7, SunSpec, MESA, 2030.5, OpenADR, etc.

d. Provide details on whether the inverter(s)/converter(s) have any intrinsic grid support functions, such as autonomous or interactive voltage and frequency support. If so, please describe these functions and default settings.

APPENDIX L - Project Construction Schedule

Utility Project Number (if available)

Project Name

Developer

* *<u>This Interconnection schedule depends upon receipt of funds along with notification to proceed, executed Interconnection Agreement, weather, equipment delivery, public opposition to right-of-way and timely Customer design submittals. Close coordination is required to sequence construction and planned interruption events. As a result, any final schedule requires mutual agreement and would be subject to change.</u>*

Milestone	**Estimated Time** **Duration to Completion (Weeks)**	**Responsible Party**
25% Payment		Interconnection Customer
Administrative Setup		Utility
Customer Submittals Single-Line and Three-Line Diagrams Stamped Site Plans		Interconnection Customer
Design Queue		Utility
Permitting/Easements		Utility
Upgrade Design – Line/POI/Substation Design		Utility: Complete design to the point of material ordering
75% Payment**		Interconnection Customer (120 Business Days after 1st Payment)
Updated Construction Schedule		Utility: Provide an Updated Construction Schedule

Updated Upgrade Cost Estimate	Upgrade Design + 10BD	Utility: Provide an Updated Upgrade Cost Estimate
Verification Test Coordination Customer Witness Testing Energization/Permission to Operate	Per SIR Timelines	Utility/Interconnection customer *Customer submittals required to be approved to schedule test*
Total Project Duration		Utility/Interconnection Customer

** *The sequence of Milestone schedule might change for non-CESIR projects*.

Appendix M –

Temporary Rules Relating to Applicants Seeking Federal Tax Credits

Introduction. On August 15, 2025, the Internal Revenue Service (IRS) issued guidelines on renewable energy project eligibility for certain federal tax credits pursuant to §§ 70512 and 70513 of Public Law 119-21, 139 Stat. 72 (July 4, 2025) and Executive Order 14315. The purpose of these rules is to support the timely interconnection of as many projects that are eligible for federal tax credits as possible.

Capitalized terms used in this Appendix not otherwise defined here shall have the meanings given to them in the Standardized Interconnection Requirements (SIRs).

These rules shall apply to all projects that are eligible for federal tax credits under the IRS guidance, regardless of technology.

A. Provisions Applicable to Group A Projects.

1. The initial participants in Group A shall be (i) those projects that have commenced construction on or before the effective date of these rules and do not require Qualifying Upgrades, and (ii) projects that must be in-service by December 31, 2027, to qualify for tax credits. Projects that commence construction after the effective date of these rules and intend to seek tax credits shall be added to Group A as provided in section 3, below.

2. Within 15 calendar days of the effective date of these rules, developers of projects included in paragraph (1) above shall provide to the relevant utilities the date on which they commenced construction, where applicable, and proposed in-service dates. Each developer and interconnecting utility shall discuss the feasibility of the proposed in-service dates. Following that consultation, the utility shall provide all developers whose projects do not require Qualifying Upgrades a schedule and a target in-service date, which may or may not be the date originally proposed by the developer, and the date when deposits required under the SIR must be released in order for the utility to achieve the target in-service date (the Release Date). The utilities shall complete this scheduling process for the initial Group A projects no later than 75 calendar days after the effective date of these rules. If a project covered by A(1)(ii) requires a Qualifying Upgrade, and the developer wishes to initiate a work plan for the upgrade, the procedures set out in section B(5)(c) below shall apply, and the projects shall be treated as Group B projects.

3. A project that commences construction after the effective date of these rules and intends to seek federal tax credits may receive a schedule as a Group A project by notifying the utility of the date on which it commenced construction and its proposed in-service date. Notifications may be made at any time after May 1, 2026. The utility shall discuss the proposed in-service date as provided above and provide the developer a schedule, target in-service date, and Release Date within 15 Business

Days of receiving the notification. In establishing schedules for entering Group A projects, utilities shall avoid delaying others previously scheduled.

4. The interconnecting utilities shall schedule and manage the work needed to interconnect Group A projects such that each project is placed in-service within the applicable time frame required by the IRS. The utilities may adjust target in-service dates and Release Dates as necessary to maximize the number of projects that achieve the IRS in-service dates. Utilities shall notify affected developers in writing via their DG portals of any change to either target in-service dates or Release Dates and the reason for the change.

5. Group A projects who do not release their deposits on or before the Release Date assigned by the utility shall be removed from Group A and shall not be scheduled under these rules. If a Group A developer anticipates missing a project's assigned Release Date, the developer may request a revised schedule. Such requests must be submitted to the utility in writing at least 15 Business Days prior to the Release Date and must include a proposed in-service date. The utility shall make reasonable efforts to re-schedule its work to meet the in-service date allowed by the IRS but shall not be required to meet the project's proposed in-service date. The utility shall provide the developer a new Release Date and, if necessary, a new target in-service date within 15 Business Days of receiving the developer's request. A project that requests a revised schedule shall be removed from Group A if:

    a. the utility cannot reschedule the work in time to meet the IRS in-service deadline for that project; or
    b. the developer does not release the deposit by the second Release Date.

6. If a project is cancelled, the interconnecting utility will stop work. Within 60 Business Days of the cancellation, the utility shall submit a final reconciliation statement as required by Step 11 of the SIRs.

7. Except for projects included in A(1) above, projects that have not initiated scheduling under these rules shall make their deposits according to the deadlines in Section 1.D of the SIRs. SIRs deposit deadlines applicable to Projects included in A(1) shall be paused until their respective Release Dates. Projects scheduled as Group A projects shall deposit 100% of the cost estimates assigned to them on or before the Release Date.

B. Provisions relating to Group B Projects. These projects require Qualifying Upgrades to interconnect. The rules recognize subgroups B.1 and B.2.

1. Qualifying Upgrade Charge payments not due prior to the effective date shall be due when required under these rules.

2. Group B.1 consists of all projects that notify the utility in writing within 30 days of the effective date of these rules that (1) they have been assigned a Qualifying Upgrade Share, and (2) they have commenced construction as defined by the IRS. In

the notification, developers shall provide the date on which they met the construction requirement and the date by which the IRS rules require them to be in-service. The utilities shall develop preliminary work plans for completing the Qualifying Upgrades necessary to interconnect the Group B.1 projects within the IRS deadlines. The utilities shall provide the preliminary work plans to the Group B.1 developers no later than May 1, 2026. Developers who decide to participate in a work plan shall make their Qualifying Upgrade Charge payments no later than June 1, 2026. Projects that paid Qualifying Upgrade Charges prior to the effective date may opt in to a work plan by confirming their payments by the same date. All projects that make or confirm payments by June 1, 2026, shall be considered Participating Projects.

3. The utilities shall revise and publish on their websites the work plans for the Qualifying Upgrades that have reached the mobilization thresholds established in Appendix E of the SIR with Group B.1 payments. Such work plans shall be published no later than July 15, 2026. A work plan shall include key development steps, time for starting and completing engineering and design, equipment procurement schedules, and construction mobilization dates. The work plan must deploy the utility resources necessary for all Participating Projects to be in service within the time allowed by the IRS. The utility may modify and re-publish a work plan as needed but all revisions must schedule the remaining work so all Participating Projects can meet the relevant IRS in-service deadline.

4. If Group B.1 project payments submitted or confirmed by June 1, 2026, do not meet the mobilization threshold with respect to a particular Qualifying Upgrade, the utility shall determine whether it can complete the upgrade in time to meet IRS deadlines. If the utility determines it can do so, it shall publish the date by which the mobilization threshold must be reached in order to complete the upgrade on time. Such a Qualifying Upgrade shall be considered open to participation. Information identifying the Qualifying Upgrade, the mobilization threshold payment deadline, and the funds needed to meet the threshold shall be posted on the utility's website. The utility shall make these determinations and publish this information no later than July 15, 2026.

5. Group B.2 consists of all other projects that commence construction and are allocated Qualifying Upgrade Shares at any time. Developers of these projects may elect to be scheduled under these rules by notifying the utility of the date when they commenced construction and their IRS in-service deadline.

    a. When a B.2 project requires a Qualifying Upgrade that is the subject of a published work plan, the B.2 project shall pay its Qualifying Upgrade Charge with the notification required above, and the utility shall add the project to the work plan.

    b. When a B.2 project requires a Qualifying Upgrade that is open to participation under section B(4) above, the project shall pay its Qualifying Upgrade Charge on or before the mobilization threshold deadline set by the utility. The utility shall publish the work plan for the upgrade once developer payments reach the mobilization threshold.

c. When a B.2 project requires a Qualifying Upgrade not covered in (a) or (b) above, the utility shall determine whether the Qualifying Upgrade can be constructed in time to meet the project's IRS deadline. If the utility concludes that the Qualifying Upgrade can be completed in time, the utility shall inform the developer and any other developers sharing the Qualifying Upgrade of the deadline by which the mobilization threshold must be met in order for the utility to construct the identified Qualifying Upgrade and meet the IRS deadlines applicable to their projects. The utility shall also post this information on its website. The deadline fixed hereunder shall be the payment due date for Qualifying Upgrade Charges from projects that depend on the same Qualifying Upgrade. If developer payments meet the mobilization threshold on or before the deadline, the utility shall publish the work plan for the upgrade.

6. Qualifying Upgrade Shares will not be refunded once the mobilization threshold is met, except under the circumstances identified in B(8) below.

7. The utilities shall diligently perform the work required to execute published work plans and construct Qualifying Upgrades in time to capture tax credits. The utilities shall update the published work plans monthly until all Participating Projects are interconnected.

8. If, after the mobilization threshold for a Qualifying Upgrade is reached, the utility determines that (1) circumstances beyond its control have made it impossible to complete the upgrade in time to achieve the in-service dates that are required by the IRS; or (2) its costs for the upgrade have increased 50% or more above the costs estimated by the utility at the time the Qualifying Upgrade was identified, the utility shall confer with the Participating Projects to determine whether they wish to proceed to interconnection.

   a. If Participating Project developers notify the utility that they choose to withdraw, the utility shall invoice the withdrawing developers for, and the developers shall pay, their shares of the actual costs incurred by the utility to that point.
   b. Participating Project developers that continue to interconnection shall not be responsible for any costs attributable to the withdrawing developers. Costs attributable to withdrawing projects shall be collected from projects that interconnect later. Any withdrawing projects that re-apply shall be charged and shall pay their shares of the actual costs incurred by the utility through completion of the upgrade, plus any non-shared cost, less any amounts paid at the time of withdrawal.

9. In the event a utility determines it cannot complete a Qualifying Upgrade in time, the utility shall consider alternative approaches to meeting IRS in-service deadlines, if requested by any of the Participating Projects. Alternative approaches must not

impact system reliability, and Participating Projects must bear the cost of implementing the alternative. Nothing in these rules requires a utility to develop a work plan for a Qualifying Upgrade that cannot be completed in time to meet IRS deadlines.

10. The utilities shall provide individual project schedules and target in-service dates to all Participating Projects, simultaneously with the publication of the relevant work plans.

C. <u>Provisions Applicable to All Projects.</u>

1. Except as provided in these rules, interconnection applicants and the utilities shall continue to follow the SIR. Projects that do not qualify for tax credits, and projects that are not scheduled hereunder as participants in Groups A and B, shall be scheduled for construction and energization in accordance with the SIR so long as no Group A or B project is delayed thereby.

2. The utilities shall have discretion to schedule their work and to revise in-service dates and work plans as necessary to maximize the number of tax credit-eligible projects that meet the in-service dates required by the IRS.

3. Utilities are authorized to spend deposit funds or draw on any standby letters of credit as needed to meet the schedules established under these rules.